# Prevention of Significant Deterioration Greenhouse Gas Permit Application

## Sand Hill Energy Center

*Del Valle, Travis County, Texas*

Original Submittal September 2013
Revised October 2013
Revised April 2014

*Prepared For*
*The City of Austin dba Austin Energy*

*Submitted to:*

*U.S. Environmental Protection Agency*
*Region VI*
*Multimedia Planning and Permitting Division*
*Fountain Place 12th Floor, Suite 1200*
*1445 Ross Avenue*
*Dallas, Texas 75202*

*Submitted by:*

*The City of Austin dba Austin Energy*
*721 Barton Springs Rd*
*Austin, Texas 78704*



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# Table of Contents

## List of Tables



## List of Figures



## List of Appendices

# List of Acronyms

| | |
|---|---|
| AVO | audio/visual/olfactory |
| BACT | Best Available Control Technology |
| Btu | British thermal unit |
| CAAA | Clean Air Act Amendments |
| CCS | carbon capture and storage |
| CFR | Code of Federal Regulations |
| CO | carbon monoxide |
| $CO_2$ | carbon dioxide |
| CTG | combustion turbine generator |
| DB | duct burner |
| DOE | US Department of Energy |
| DLN | dry low-$NO_x$ |
| F | Fahrenheit |
| FIP | Federal Implementation Plan |
| Ft | feet |
| GE | General Electric |
| GHG | greenhouse gas |
| GWP | global warming potential |
| $H_2O$ | water |
| HAP | Hazardous Air Pollutant |
| HHV | higher heating value |
| HRSG | heat recovery steam generator |
| HP | high pressure |
| IP | intermediate pressure |
| K | degrees on the Kelvin scale |
| kW | kilowatt |
| LAER | Lowest Achievable Emission Rate |
| lb/hr | pounds per hour |
| lb/MMBtu | pounds per million British thermal units |

| | |
|---|---|
| LHV | lower heating value |
| LP | low pressure |
| MACT | Maximum Achievable Control Technology |
| MMBtu/hr | million British thermal units per hour |
| MW | Megawatt |
| NETL | National Energy Technology Laboratory |
| $NO_x$ | nitrogen oxides |
| NSPS | New Source Performance Standards |
| NSR | New Source Review |
| NTIS | National Institute of Standards and Technology |
| $O_2$ | oxygen |
| ppmvd | parts per million by volume, dry basis |
| PNG | pipeline natural gas |
| PSD | Prevention of Significant Deterioration |
| PTE | potential to emit |
| RACT | Reasonably Available Control Technology |
| RBLC | RACT/BACT/LAER Clearinghouse |
| SAR | South Austin Regional |
| SHEC | Sand Hill Energy Center |
| scf | standard cubic feet |
| SCR | Selective Catalytic Reduction |
| SER | Significant Emission Rate |
| SIP | State Implementation Plan |
| STG | steam turbine generator |
| TCEQ | Texas Commission on Environmental Quality |
| Tpy | tons per year |
| USEPA | United States Environmental Protection Agency |
| VOC | volatile organic compounds |

# Executive Summary

The City of Austin (dba Austin Energy) is proposing to build-out the Sand Hill Energy Center (SHEC) located in Del Valle, Texas by adding a new pipeline natural gas (PNG) fired combustion turbine generator (CTG) and heat recovery steam generator (HRSG) with natural gas fired duct burners to the existing combined cycle electricity generating unit at SHEC. The new unit will share the existing 189 MW steam turbine generator (STG) with the combustion turbine and HRSG associated with existing combined cycle unit. The proposed new combustion turbine generator is an updated version of the same General Electric (GE) Model 7FA unit currently in operation as part of the combined cycle unit.

Because the SHEC facility is an existing major source of greenhouse gas (GHG) emissions and the project increases facility GHG emissions by more than 75,000 tons per year on a carbon dioxide equivalent (CO2e) basis, the project is also subject to prevention of significant deterioration (PSD) new source review program for GHG emissions. EPA is authorized under a Federal Implementation Plan (FIP) to issue PSD permits in Texas for GHG sources until Texas submits the required SIP revision for GHG permitting and it is approved by EPA. The key element of PSD review for GHG is the best available control technology (BACT) analysis.

Sources of GHG emissions include the combustion turbine and duct burner combustion emissions of carbon dioxide ($CO_2$), nitrous oxide ($N_2O$) and methane ($CH_4$), the natural gas piping component leaks and other releases of natural gas (including $CH_4$) and the electric circuit breaker sulfur hexafluoride ($SF_6$) leak emissions. The latter two sources are minimal compared to the combined cycle emissions and BACT is addressed for these with a combination of effective design and work practices.

The BACT analysis for the proposed new combined cycle unit's GHG emissions evaluates two applicable options: carbon capture and sequestration (CCS) and energy efficiency measures. As with other recent GHG BACT analyses for permits for similar units, it was determined that the CCS technology currently has significant technical hurdles but may also rule out based on poor cost-effectiveness, with the capital cost of carbon capture, transport and storage exceeding the capital cost of the proposed project. As such, electrical generation efficiency measures are proposed as BACT for the project GHG emissions. This BACT technology determination is supported based on the low-carbon pipeline natural gas fuel, and the very efficient combustion turbine combined cycle technology, which compares favorably to similar units.

Consistent with recent GHG PSD permits for natural gas-fired combined cycle projects, the proposed BACT emission limits include and output-based GHG limit (ton CO2e/MWh), a heat rate limit (Btu/kWh) and an overall GHG emissions cap that takes into account start-up, part-load and duct burner emissions. Because of facility-specific design considerations, specifically the proposed CTG, HRSG and duct burner sharing an STG with another CTG, HRSG and duct burner that are not subject to GHG BACT, the proposed GHG emission limits must take a slightly different form that those for other brand new 2x1 combined cycle units. A typical combined cycle unit that is designed and built with one or more CTGs and STGs is amenable to a limit that includes the electric generation output of both the CTGs and STGs, in order to "take credit" for the excellent efficiency associated with this combined cycle technology and show very low GHG ton/MWh limits and Btu/kWh heat rate limits. Because of the shared STG in this "2 on 1" configuration, it is not possible to determine how much of the output generated by the steam turbine is attributable to the new CTG and HRSG versus the existing CTG and HRSG. As such, Austin Energy is proposing that the new unit's GHG limits be based on the output of the combustion turbine alone. As such, the proposed limits are greater in terms of the proposed ton/MWh and Btu/kWh limits, but are shown to be comparable to GHG BACT combined cycle limits (based on CTG and STG output) in recently issued permits.

# Section 1
# Introduction

The City of Austin (dba Austin Energy) is proposing to build-out the Sand Hill Energy Center (SHEC) located in Del Valle, Travis County, Texas by adding to the existing combined cycle unit at the facility. The existing combined cycle unit at the SHEC was conceived and constructed to include this new unit when Austin's energy demands grew to the point where additional generating capacity would be required. The proposed project will add a new pipeline natural gas (PNG) fired combustion turbine and heat recovery steam generator (HRSG) to the existing combined cycle electricity generating unit at SHEC. A site location map is included as Figure 1-1 and a plot plan of the existing and proposed facility is presented as Figure 1-2.

Construction will include the installation of a General Electric (GE) model 7FA.04 combustion turbine and a heat recovery steam generator (HRSG) with natural gas fired duct burners (the Project). The new combustion turbine generator (CTG) is rated at 187 MW at International Standard Organization conditions. The new combined cycle unit will share an existing 189 MW steam turbine generator (STG) which is part of the existing combined cycle unit. Proposed emission controls technology includes dry low-NOx (DLN) combustion and selective catalytic reduction (SCR) for nitrogen oxides ($NO_x$) emission control and an oxidation catalyst to reduce emissions of carbon monoxide (CO) and volatile organic compounds (VOC).

The City of Austin will submit an amendment application to the Texas Commission on Environmental Quality (TCEQ) to authorize the addition of this second combustion turbine and HRSG at its SHEC facility. On June 3, 2010, the U.S. Environmental Protection Agency (EPA) published final rules for permitting sources of greenhouse gases (GHGs) under the prevention of significant deterioration (PSD) and Title V air permitting programs, known as the GHG Tailoring Rule.[1] After July 1, 2011, new sources having the potential to emit more than 100,000 tons per year of GHGs and modifications increasing GHG emissions more than 75,000 tons per year on a carbon dioxide equivalent (CO2e) basis at existing major sources are subject to GHG PSD review, regardless of whether PSD is triggered for other pollutants. The existing SHEC facility is an existing PSD major source based on potential criteria pollutant emissions greater than 250 tons per year and GHG emissions greater than 100,000 tons per year of CO2e.

[1] 75 FR 31514 (June 3, 2010)

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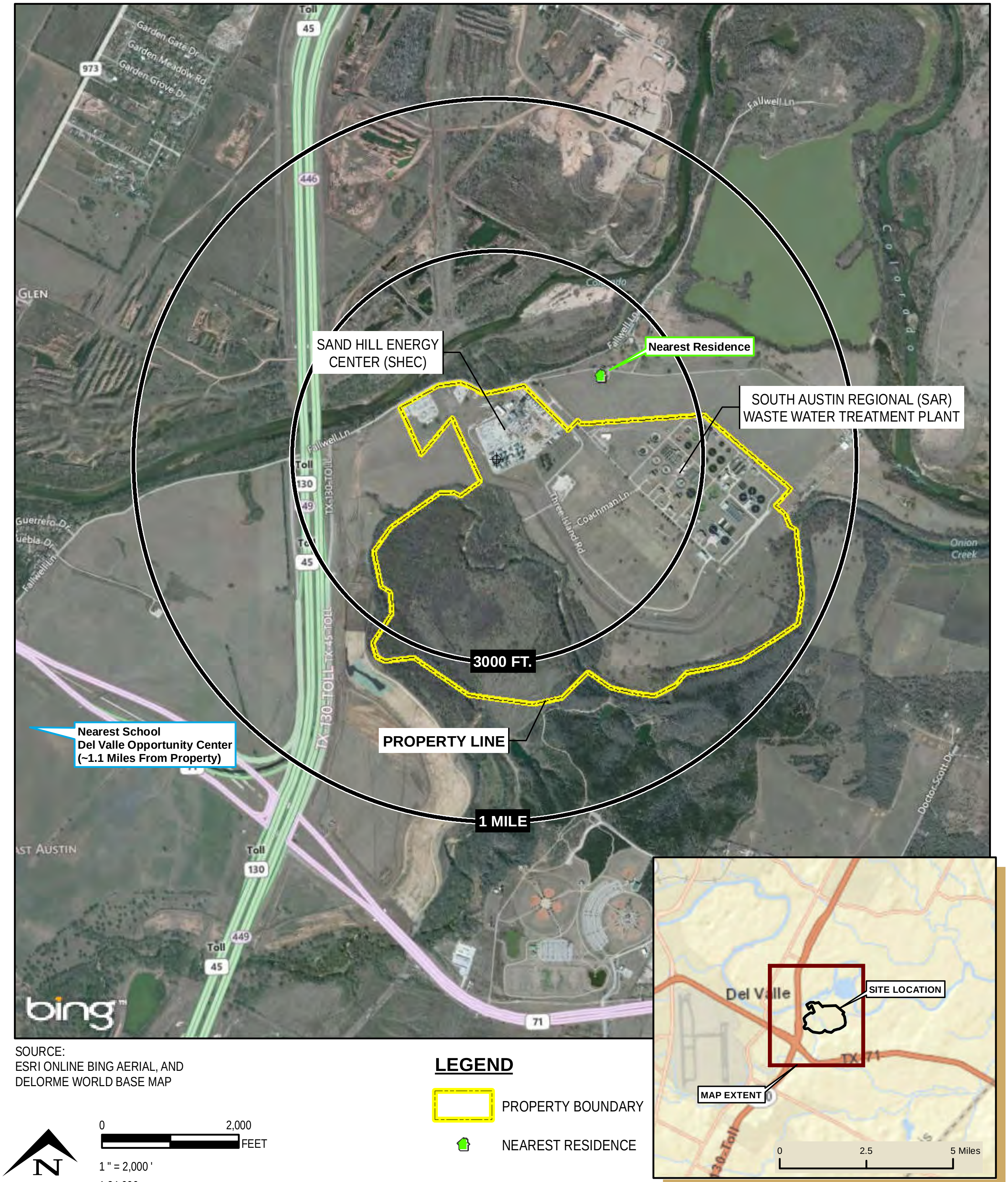
TRC - GIS




SOURCE:
ESRI ONLINE BING AERIAL, AND
DELORME WORLD BASE MAP

N

0 2,000 FEET

1 " = 2,000 '

1:24,000

**LEGEND**

PROPERTY BOUNDARY

NEAREST RESIDENCE


TRC

10011 Meadowglen Lane
Houston, TX 77042
Phone: 713.244.1000

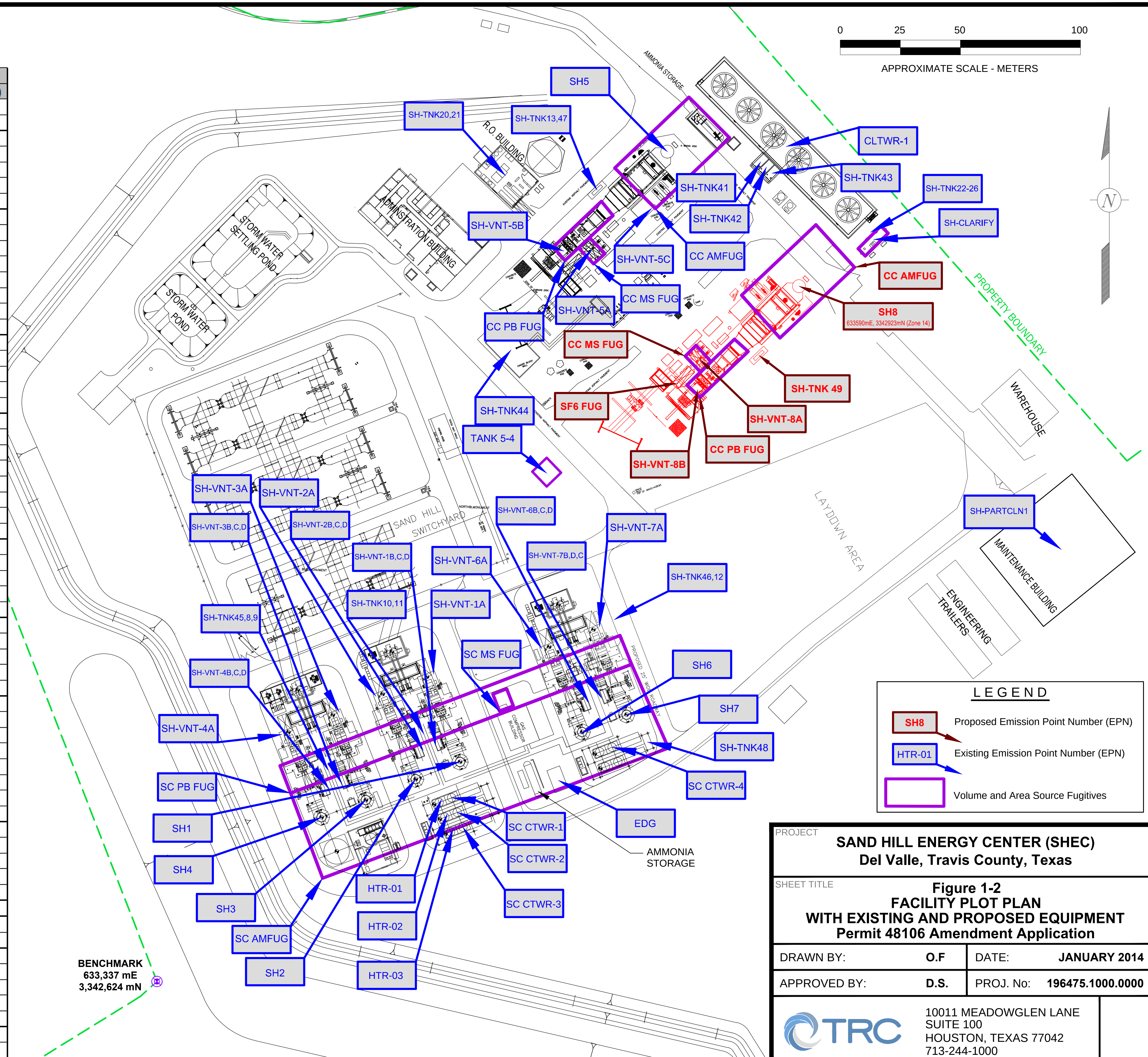

**SAND HILL ENERGY CENTER**
**DEL VALLE, TRAVIS COUNTY, TEXAS**

**FIGURE 1-1**
**SITE LOCATION MAP**

| | |
|---|---|
| DRAWN BY: | PAPEZ J |
| APPROVED BY: | STANKO E |
| PROJECT NO: | 196475-001-002 |
| FILE NO. | 196475-002am1.mxd |
| DATE: | AUGUST 2013 |

E:\CityofAustinTX\2012_196475\196475-002am1.mxd

| EPN / FIN | SOURCE NAME | UTM COORDINATES | |
|---|---|---|---|
| | | Easting (m) | Northing (m) |
| **EXISTING SOURCES** | | | |
| SH1 | GE LM 6000 Simple Cycle Gas Turbine 1 | 633,456 | 3,342,718 |
| SH2 | GE LM 6000 Simple Cycle Gas Turbine 2 | 633,438 | 3,342,710 |
| SH3 | GE LM 6000 Simple Cycle Gas Turbine 3 | 633,419 | 3,342,703 |
| SH4 | GE LM 6000 Simple Cycle Gas Turbine 4 | 633,401 | 3,342,695 |
| SH5 | GE 7FA.03 Combined Cycle Unit 5 | 633,535 | 3,342,976 |
| SH6 | GE LM 6000 Simple Cycle Gas Turbine 6 | 633,506 | 3,342,733 |
| SH7 | GE LM 6000 Simple Cycle Gas Turbine 7 | 633,524 | 3,342,740 |
| HTR-01 | Inlet Air Heater 1 | 633,448 | 3,342,701 |
| HTR-02 | Inlet Air Heater 2 | 633,451 | 3,342,695 |
| HTR-03 | Inlet Air Heater 3 | 633,453 | 3,342,689 |
| SC CTWR-1 | Simple Cycle Cooling Tower 1 | 633,453 | 3,342,703 |
| SC CTWR-2 | Simple Cycle Cooling Tower 2 | 633,456 | 3,342,697 |
| SC CTWR-3 | Simple Cycle Cooling Tower 3 | 633,458 | 3,342,691 |
| SC CTWR-4 | Simple Cycle Cooling Tower 4 | 633,521 | 3,342,721 |
| CLTWR-1 | Cooling Tower 1 (Combined Cycle) | 633,587 | 3,342,971 |
| SC PB FUG | Simple Cycle Power Block Fugitives | 633,388 | 3,342,704 |
| SC MS FUG | Simple Cycle Natural Gas Meter Skid | 633,475 | 3,342,738 |
| CC PB FUG | Combined Cycle Power Block Fugitives | 633,502 | 3,342,926 |
| CC MS FUG | Combined Cycle Natural Gas Meter Skid | 633,514 | 3,342,925 |
| SC AMFUG | Simple Cycle Ammonia Fugitives | 633,403 | 3,342,669 |
| CC AMFUG | Combined Cycle Ammonia Fugitives | 633,513 | 3,342,965 |
| TANK 5-4 | Oil/Water Separator | 633,495 | 3,342,838 |
| EDG | Emergency Diesel Generator | 633,494 | 3,342,713 |
| SH-VNT-1A | Generator Lube Oil Vent-1A | 633,448 | 3,342,754 |
| SH-VNT-1B,C,D | Lube Oil Vents-1B,C,D | 633,449 | 3,342,724 |
| SH-VNT-2A | Generator Lube Oil Vent-2A | 633,424 | 3,342,744 |
| SH-VNT-2B,C,D | Lube Oil Vents-2B,C,D | 633,443 | 3,342,722 |
| SH-VNT-3A | Generator Lube Oil Vent-3A | 633,408 | 3,342,738 |
| SH-VNT-3B,C,D | Lube Oil Vents-3B,C,D | 633,409 | 3,342,708 |
| SH-VNT-4A | Generator Lube Oil Vent-4A | 633,384 | 3,342,728 |
| SH-VNT-4B,C,D | Lube Oil Vents-4B,C,D | 633,404 | 3,342,706 |
| SH-VNT-5A | Hydraulic Oil/Lube Oil Vent on Unit 5A Gas Turbine | 633,513 | 3,342,930 |
| SH-VNT-5B | Generator Seal Oil Vent for Unit 5 Gas Turbine | 633,502 | 3,342,930 |
| SH-VNT-5C | Lube Oil Vent on Unit 5C Steam Turbine | 633,539 | 3,342,948 |
| SH-VNT-6A | Generator Lube Oil Vent-6A | 633,493 | 3,342,764 |
| SH-VNT-6B,C,D | Lube Oil Vents-6B,C,D | 633,512 | 3,342,742 |
| SH-VNT-7A | Generator Lube Oil Vent-7A | 633,517 | 3,342,773 |
| SH-VNT-7B,D,C | Lube Oil Vents-7B,D,C | 633,518 | 3,342,744 |
| SH-PARTCLN1 | Parts Cleaner | 633,709 | 3,342,806 |
| SH-TNK10,11 | Underground Wash Water Tanks | 633,444 | 3,342,728 |
| SH-TNK13,47 | Underground Wash Water Tanks | 633,478 | 3,342,961 |
| SH-TNK20,21 | Nalco Tote Tanks | 633,516 | 3,342,955 |
| SH-TNK22-26 | Nalco Tote Tanks | 633,630 | 3,342,938 |
| SH-TNK46,12 | Oil/Water Seperator Tank for Units 6-7 | 633,523 | 3,342,776 |
| SH-TNK41 | Circulating Water Pump/Lube Oil Reservoir | 633,584 | 3,342,967 |
| SH-TNK42 | Circulating Water Pump/Lube Oil Reservoir | 633,586 | 3,342,965 |
| SH-TNK43 | Circulating Water Pump/Lube Oil Reservoir | 633,589 | 3,342,962 |
| SH-TNK44 | Unit 5 Gas Compressor Oil Reservoir | 633,480 | 3,342,889 |
| SH-TNK45 | Oil/Water Seperator Tank for Units 1-4 | 633,404 | 3,342,713 |
| SH-TNK48 | Underground Wash Water Tank | 633,537 | 3,342,725 |
| SH-CLARIFY | Water Treatment Chemical Storage Tanks | 633,631 | 3,342,935 |
| **PROPOSED SOURCES** | | | |
| SH8 | GE 7FA.04 Combined Cycle Unit 8 | 633,590 | 3,342,923 |
| CC AMFUG | Combined Cycle Ammonia Fugitives Unit 8 | 633,576 | 3,342,911 |
| CC MS FUG | Combined Cycle Natural Gas Meter Skid Unit 8 | 633,553 | 3,342,885 |
| CC PB FUG | Combined Cycle Power Block Fugitives Unit 8 | 633,553 | 3,342,874 |
| SF6 FUG | SF6 Fugitives | 633,549 | 3,342,875 |
| SH-TNK49 | Underground Wash Water Tank | 633,583 | 3,342,886 |
| SH-VNT-8A | Hydraulic Oil/Lube Oil Vent on Unit 8 Gas Turbine | 633,559 | 3,342,885 |
| SH-VNT-8B | Generator Seal Oil Vent for Unit 8 Gas Turbine | 633,558 | 3,342,872 |




PROJECT

**SAND HILL ENERGY CENTER (SHEC)**
**Del Valle, Travis County, Texas**

SHEET TITLE

**Figure 1-2**
**FACILITY PLOT PLAN**
**WITH EXISTING AND PROPOSED EQUIPMENT**
**Permit 48106 Amendment Application**

| DRAWN BY: | O.F | DATE: | JANUARY 2014 |
|---|---|---|---|
| APPROVED BY: | D.S. | PROJ. No: | 196475.1000.0000 |

TRC
10011 MEADOWGLEN LANE
SUITE 100
HOUSTON, TEXAS 77042
713-244-1000

HOU L:\Sand Hill Energy Center - SHEC\ Figs A-1 n 3-1 - CofA-SHEC - Plot Plan-w-EXISTINGnPROPOSED Equipment.dwg 01/27/14

On December 23, 2010, EPA issued a Federal Implementation Plan (FIP) authorizing EPA to issue PSD permits in Texas for GHG sources until Texas submits the required SIP revision for GHG permitting and it is approved by EPA.[2]

The SHEC proposed Project for the addition of a second combined cycle combustion turbine triggers PSD review for GHG regulated pollutants because the project will increase GHG emissions by more than 75,000 tons/year and the site is an existing major PSD source. This application is being submitted to EPA pursuant to its regulatory authority under the FIP. Included in this application is a project description including a description of current operations, GHG emissions calculations, a PSD applicability determination and a GHG Best Available Control Technology (BACT) analysis. TCEQ permit application forms, emission calculations, and BACT analysis documentation are appended to this document.

[2] 75 FR 81874 (December 29, 2010)

# Section 2
# Project Description

## 2.1 Need for the Facility and Conceptual Design

Austin Energy requires additional generation to support a fast growing population and job growth in both the City of Austin and Travis County. Austin has been the fastest growing city in the country for the past three years. Since 2009 the population of Travis County has increased by 98,415 individuals, an increase of almost 10%[3]. Current projections indicate that county population is expected to continue to increase at this rate adding another 102,000 people by 2017[4]. Travis County has added 67,186 new jobs since 2009[5] and this trend is expected to continue and keep pace with the projected population growth. The existing STG at the SHEC was sized to allow for population growth and increased power demands by accommodating the installation of an additional combustion turbine and HRSG.

Annual residential electricity consumption in Texas for 2011 was 145,654,228 MWh, an increase of 15,857,077 MWh (or 10.9%) from just two years earlier[6]. The population of the state increased by 892,379 individuals over this same two-year period, growing from 24,782,302 to 25,674,681 as of July 1, 2011 [7].

Based on the current average residential electricity usage per person of 5.673 MWh/yr/person for Texas, and a projected population increase in Travis County of over 200,000 persons from 2009 to 2017, the residential electricity demand is projected to increase by 1,136,968 MWh/year. The maximum additional capacity of the new unit is approximately 206 MW and this translates to 1,443,648 MWh annually based on a capacity factor of 80%. Therefore, the projected increase in local residential demand alone (over an eight-year period) represents 79% of the additional power available from the project.

## 2.2 The Existing SHEC Facility

The existing facility equipment, operations and emissions are regulated under Prevention of Significant Deterioration (PSD) permit No PSDTX1012M1 and Texas Commission on Environmental Quality (TCEQ) Permit No. 48106. The current generating units include six natural gas fired GE LM6000 aero derivative design simple cycle combustion turbines and the

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[3] Perryman Group

[4] Population estimates from Perryman Group

[5] Travis County employment from the Texas Workforce Commission

[6] Energy Information Administration

[7] US Census

existing natural gas fired GE Frame 7FA combustion turbine combined cycle unit including natural gas fired duct burners, a HRSG and a steam turbine generator. The six simple cycle units are designated in the permit as EPN's SH1, SH2, SH3, SH4, SH6 and SH7. The first four units (SH1-4) commenced operation in 2001 and the two newer units (SH6 and SH7) commenced operation in 2010. These units have a nominal output rating of 50 MW each and serve as "peaking" units that start up to help meet demand during peak (higher) periods. The LM6000 turbines utilize GE's spray inter-cooled turbine (Sprint) design and power augmentation and include water injection and SCR for $NO_x$ control.

The existing combined cycle unit commenced operation in 2004 and is designated in the TCEQ PSD permit as EPN SH5 and has a GE 7FA.03 combustion turbine – a previous version of the 7FA model. The turbine is equipped with dry low $NO_x$ (DLN) (model DLN2.6) combustors. Its HRSG is equipped with natural gas fired duct burners and SCR. The steam turbine generator for this unit was sized to accommodate the addition of a second similarly sized combustion turbine, with a space immediately adjacent to the southeast of the SH5 unit for the proposed SH8 unit, as shown in the plot plan in Figure 1-2. The current combined cycle unit is a one-on-one (1 x 1) configuration (one CTG with HRSG and one STG), but following the addition of the proposed new turbine and HRSG it will be a 2 x 1 configuration (two CTGs/HRSGs and one STG). The present combustion turbine has nominal rated output of 164 MW and the steam turbine generator currently produces up to 157 MW but will be capable of up to 189 MW output with the addition of the proposed second combustion turbine. As such, the maximum combined generating output of the combined cycle unit will increase from 321 MW for the existing 1 x 1 configuration to 553 MW for the proposed 2 x 1 configuration. The STG was originally sized for the planned build-out to a 2 x 1 configuration.

The existing cooling tower was sized for the full STG capacity in the 2 x 1 configuration, so no new cooling tower capacity is needed. Saturated steam from the STG is condensed prior to being recirculated along with makeup water to the HRSG for reheating. Condenser cooling is provided by circulating water that is in turn cooled by ambient air in the direct-contact mechanical draft cooling tower. The water that is used in the cooling tower makeup is either potable water or reclaimed water and river water from the Colorado River that is treated onsite. The reclaimed water is obtained from the adjoining South Austin Regional (SAR) wastewater treatment plant.

Ancillary equipment includes two existing aqueous ammonia storage tanks (19% aqueous ammonia solution) that store the SCR reagent for the units. One aqueous ammonia tank stores SCR reagent for all six simple cycle turbines. The other tank stores ammonia solution for the combined cycle unit and would also serve the proposed new unit. The aqueous ammonia goes to a vaporizer unit and is then injected into the flue gas upstream of the SCR catalyst. There are also four existing cooling towers and three natural gas fired inlet air heaters associated with the simple cycle units and one existing cooling tower associated with the combined cycle unit.

## 2.3 The Proposed Project

The new combined cycle unit is anticipated to operate as a base-loaded unit, with up to 8,760 full-load hours per year, but may also operate at partial loads, and/or start-up and shutdown as needed to meet electricity demand. The duct burners for the new unit will be rated at 681.5 MMBtu/hr based on the higher heating value (HHV) of the pipeline natural gas fuel, and may operate at full capacity for up to 8760 hours per year. The new combined cycle turbine is expected to start-up numerous times per year.

As described above, the new combustion turbine and HRSG will be located alongside the existing GE 7FA.03 turbine that is presently operating in combined cycle mode in a 1 x 1 configuration with a single CTG/HRSG supplying steam to a single STG. The existing STG is sized such that it will be able to accommodate the build-out with additional steam from the new HRSG of the proposed GE 7FA.04 combustion turbine; thus the new configuration will be 2 x 1 with two CTGs/HRSGs supplying steam to one STG.

The proposed combustion turbine will utilize DLN combustors and SCR to control NOx emissions. Aqueous ammonia from the existing combined cycle ammonia storage tank will be vaporized in a new ammonia vaporizer dedicated to the SCR for the proposed unit. The proposed PNG-fired duct burner will have a maximum heat input capacity of 681.5 MMBtu/hr (HHV). An oxidation catalyst will be located in the HRSG downstream of the duct burners and upstream of the SCR ammonia injection grid and will control emissions of CO as well as VOC.

GHG emissions from the proposed Project are discussed in detail in Section 3 of this application. A facility plot plan with existing and proposed equipment labeled is included as Figure 2-1. A process flow diagram for the proposed unit is included as Figure 2-2 and a process flow diagram that shows integration of the proposed unit with the existing combined cycle unit is included as Figure 2-3.

There are no upstream or downstream impacts that would preclude addition of the proposed unit to the SHEC, because the existing the plant natural gas piping and infrastructure is designed to handle a second GE 7FA combustion turbine and duct burner. The existing steam turbine was designed to achieve full capacity with a second GE 7FA and HRSG, which would improve the heat rate and thermal efficiency of the unit, providing more electricity per unit of natural gas consumed. The existing balance of plant equipment including circulating water, condensate water, cooling water systems and the cooling tower were designed to support an additional 7FA and HRSG.

HOU L:\City of Austin\Sand Hill Energy Center - SHEC\ Fig 1-2 n 2-1 - CofA-SHEC - Plot Plan-w-SH8.dwg 09/09/13

| EPN / FIN | SOURCE NAME | UTM COORDINATES | |
|---|---|---|---|
| | | Easting (m) | Northing (m) |
| **EXISTING SOURCES** | | | |
| SH1 | GE LM 6000 Simple Cycle Gas Turbine 1 | 633,456 | 3,342,718 |
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| SH4 | GE LM 6000 Simple Cycle Gas Turbine 4 | 633,401 | 3,342,695 |
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| HTR-03 | Inlet Air Heater 3 | 633,453 | 3,342,689 |
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| SC CTWR-2 | Simple Cycle Cooling Tower 2 | 633,456 | 3,342,697 |
| SC CTWR-3 | Simple Cycle Cooling Tower 3 | 633,458 | 3,342,691 |
| SC CTWR-4 | Simple Cycle Cooling Tower 4 | 633,521 | 3,342,721 |
| CLTWR-1 | Cooling Tower 1 (Combined Cycle) | 633,587 | 3,342,971 |
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| SC MS FUG | Simple Cycle Natural Gas Meter Skid | 633,475 | 3,342,738 |
| CC PB FUG | Combined Cycle Power Block Fugitives | 633,502 | 3,342,926 |
| CC MS FUG | Combined Cycle Natural Gas Meter Skid | 633,514 | 3,342,925 |
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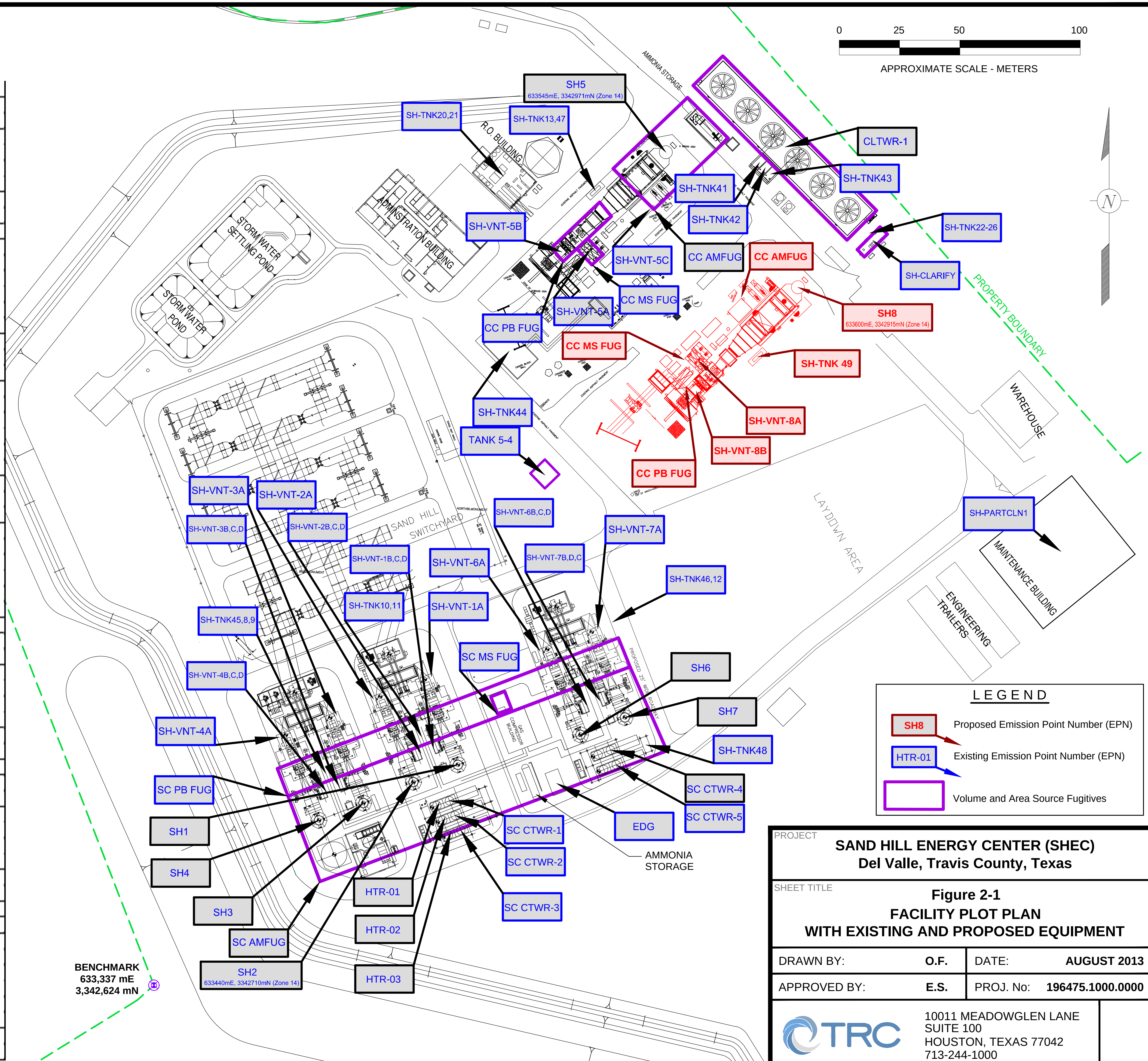
| SH-VNT-2A | Generator Lube Oil Vent-2A | 633,424 | 3,342,744 |
| SH-VNT-2B,C,D | Lube Oil Vents-2B,C,D | 633,443 | 3,342,722 |
| SH-VNT-3A | Generator Lube Oil Vent-3A | 633,408 | 3,342,738 |
| SH-VNT-3B,C,D | Lube Oil Vents-3B,C,D | 633,409 | 3,342,708 |
| SH-VNT-4A | Generator Lube Oil Vent-4A | 633,384 | 3,342,728 |
| SH-VNT-4B,C,D | Lube Oil Vents-4B,C,D | 633,404 | 3,342,706 |
| SH-VNT-5A | Hydraulic Oil/Lube Oil Vent on Unit 5A Gas Turbine | 633,513 | 3,342,930 |
| SH-VNT-5B | Generator Seal Oil Vent for Unit 5 Gas Turbine | 633,502 | 3,342,930 |
| SH-VNT-5C | Lube Oil Vent on Unit 5C Steam Turbine | 633,549 | 3,342,948 |
| SH-VNT-6A | Generator Lube Oil Vent-6A | 633,493 | 3,342,764 |
| SH-VNT-6B,C,D | Lube Oil Vents-6B,C,D | 633,512 | 3,342,742 |
| SH-VNT-7A | Generator Lube Oil Vent-7A | 633,517 | 3,342,773 |
| SH-VNT-7B,D,C | Lube Oil Vents-7B,D,C | 633,518 | 3,342,744 |
| SH-PARTCLN1 | Parts Cleaner | 633,709 | 3,342,806 |
| SH-TNK10,11 | Underground Wash Water Tanks | 633,444 | 3,342,728 |
| SH-TNK13,47 | Underground Wash Water Tanks | 633,478 | 3,342,961 |
| SH-TNK20,21 | Nalco Tote Tanks | 633,516 | 3,342,955 |
| SH-TNK22-26 | Nalco Tote Tanks | 633,630 | 3,342,938 |
| SH-TNK46,12 | Oil/Water Seperator Tank for Units 6-7 | 633,523 | 3,342,776 |
| SH-TNK41 | Circulating Water Pump/Lube Oil Reservoir | 633,584 | 3,342,967 |
| SH-TNK42 | Circulating Water Pump/Lube Oil Reservoir | 633,586 | 3,342,965 |
| SH-TNK43 | Circulating Water Pump/Lube Oil Reservoir | 633,589 | 3,342,962 |
| SH-TNK44 | Unit 5 Gas Compressor Oil Reservoir | 633,480 | 3,342,889 |
| SH-TNK45 | Oil/Water Seperator Tank for Units 1-4 | 633,404 | 3,342,713 |
| SH-TNK48 | Underground Wash Water Tank | 633,537 | 3,342,725 |
| SH-CLARIFY | Water Treatment Chemical Storage Tanks | 633,631 | 3,342,935 |
| **PROPOSED SOURCES** | | | |
| SH8 | GE 7FA.04 Combined Cycle Unit 8 | 633,590 | 3,342,923 |
| CC AMFUG | Combined Cycle Ammonia Fugitives Unit 8 | 633,576 | 3,342,911 |
| CC MS FUG | Combined Cycle Natural Gas Meter Skid Unit 8 | 633,553 | 3,342,885 |
| CC PB FUG | Combined Cycle Power Block Fugitives Unit 8 | 633,553 | 3,342,874 |
| SH-TNK49 | Underground Wash Water Tank | 633,583 | 3,342,886 |
| SH-VNT-8A | Hydraulic Oil/Lube Oil Vent on Unit 8 Gas Turbine | 633,559 | 3,342,885 |
| SH-VNT-8B | Generator Seal Oil Vent for Unit 8 Gas Turbine | 633,558 | 3,342,872 |




PROJECT

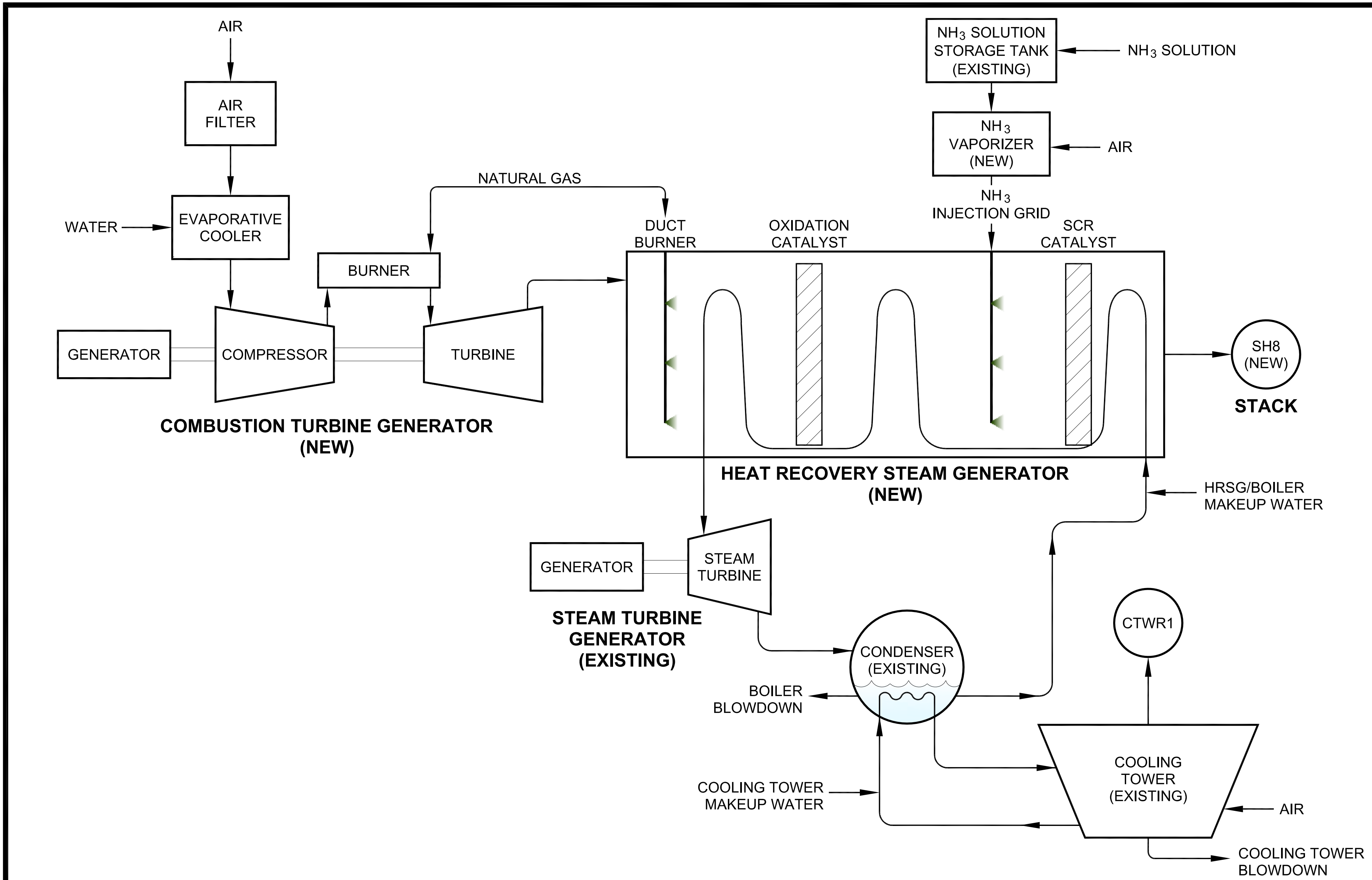
**SAND HILL ENERGY CENTER (SHEC)**
**Del Valle, Travis County, Texas**

SHEET TITLE

**Figure 2-1**
**FACILITY PLOT PLAN**
**WITH EXISTING AND PROPOSED EQUIPMENT**

| | | | |
|---|---|---|---|
| DRAWN BY: | O.F. | DATE: | AUGUST 2013 |
| APPROVED BY: | E.S. | PROJ. No: | 196475.1000.0000 |

TRC
10011 MEADOWGLEN LANE
SUITE 100
HOUSTON, TEXAS 77042
713-244-1000




10011 MEADOWGLEN LANE
SUITE 100
HOUSTON, TEXAS 77042
713-244-1000

PROJECT

**SAND HILL ENERGY CENTER (SHEC)**

Del Valle, Travis County, Texas

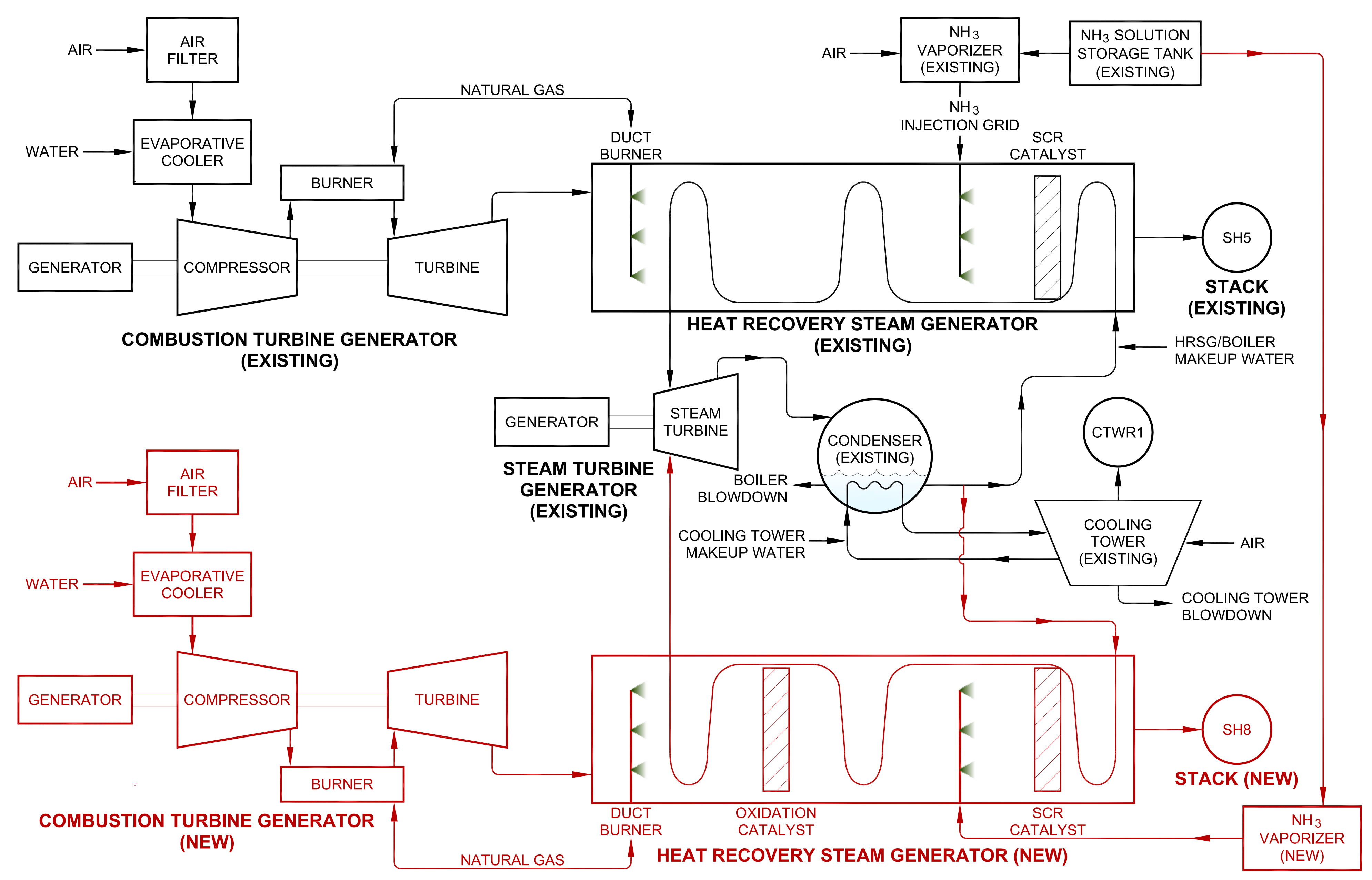
SHEET TITLE

Figure 2-2

**PROCESS FLOW DIAGRAM - PROPOSED COMBINED CYCLE UNIT**

| | |
|---|---|
| DRAWN BY: | O.F. |
| APPROVED BY: | G.E. |
| PROJ. No: | 196475.0000.0000 |
| DATE: | AUGUST 2013 |

HOU L:\City of Austin\Sand Hill Energy Center - SHEC\ Fig 2-3 n 5-2 - CofA-SHEC - PFD -Existing-n-New.dwg 08/19/13




TRC

10011 MEADOWGLEN LANE
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HOUSTON, TEXAS 77042
713-244-1000

PROJECT

**SAND HILL ENERGY CENTER (SHEC)**
Del Valle, Travis County, Texas

SHEET TITLE

Figure 2-3

**PROCESS FLOW DIAGRAM FOR EXISTING AND PROPOSED COMBINED CYCLE UNIT**

| | |
|---|---|
| DRAWN BY: | O.F. |
| APPROVED BY: | D.S. |
| PROJ. No: | 196475.0000.0000 |
| DATE: | AUGUST 2013 |

The existing condenser was constructed to support steam flow from a second HRSG operating in bypass. The plant switchyard is designed to support the electrical production of the additional unit. The plant access road is adequate to support construction and maintain operation of the additional unit. There will be small increases of natural gas fugitives from piping associated with the proposed CTG.

The cooling tower, which uses water from the adjacent City of Austin waste water treatment plant and or potable water or river water, will require additional make-up water. There would also be an increased volume of process water and equipment cooling water usage. There will also be small increases in wastewater due to blow-down from the new HRSG.

## 2.4 Process Description

The GE 7FA.04 CTG consists of a compressor, burners, turbine and generator on a single shaft as shown in Figure 2-2. Ambient air is introduced to the unit after inlet air filtration and (on high temperature days) evaporative cooling, where an atomized mist of water is used to reduce the air temperature, increasing air density and thus increasing the output of the turbine. Filtered (and cooled) air is compressed in the compressor section prior to combustion with PNG in the combustion zone. Products of combustion from the burner go to the turbine section where they expand to rotate the turbine that drives the compressor and the generator. The exhaust gas exits the turbine at approximately 1100°F and is delivered to the HRSG via ductwork. The HRSG design is a 3-pressure reheat design with high-pressure (HP), intermediate pressure (IP) and low pressure (LP) sections. A duct burner may be used to deliver additional heat to the HP section of the HRSG by combustion of pipeline natural gas using residual oxygen in the flue gas. Heat recovered in the HRSG will be utilized to produce steam.

High pressure steam generated within the HRSG will be used to drive the existing STG and associated electrical generator attached to the same shaft. After expansion in the steam turbine, saturated steam goes to a condenser and is cooled back to water before being returned to the HRSG for reuse. The condenser is cooled via a closed cycle cooling water loop that uses a cooling tower to maintain the circulating water temperature low enough for effective condenser operation. The mechanical induced draft cooling tower uses large fans to draw air into the tower and across the path of the water so that direct contact and heat transfer is made between the hot water and cooler air. Some of the cooling water is lost via evaporation and drift (droplets) and some additional water is lost to blow-down (used to keep solids concentrations from building up) and must be made up via introduction of make-up water to the circulating cooling water. The cooling tower is equipped with mist eliminators to minimize drift and conserve water.

### 2.4.1 Emission Control Equipment for the Combined Cycle Unit

The emission control technologies proposed for the combustion turbine and duct burner exhaust gases include DLN combustors located within the combustion turbine and an SCR system located within the HRSG to control $NO_x$ emissions. An oxidation catalyst and efficient combustion controls will be used to control emissions of CO and VOC. Emissions of other pollutants are minimized through the proposed use of low-sulfur pipeline natural gas, as well as efficient combustion in the combustion turbine and duct burner.

## 2.5 Natural Gas Piping

Austin Energy is proposing to utilize PNG as the only fuel for the proposed combustion turbine and duct burner. The natural gas is delivered to the site via an existing natural gas pipeline that serves the site. Gas will be metered and piped to the new combustion turbine and duct burner. The natural gas is assumed to have a HHV of 1,022 Btu/standard cubic foot (scf) and a maximum sulfur content of 0.23 grains per 100 scf. Fugitive emissions from any new gas piping components associated with the new combined cycle unit will include emissions of methane and carbon dioxide, components of the natural gas.

## 2.6 Electrical Equipment Insulated with Sulfur Hexafluoride ($SF_6$)

Sulfur hexafluoride ($SF_6$) is a fluorinated compound with an extremely stable molecular structure. The unique chemical properties of $SF_6$ make it an efficient electrical insulator. The gas is used for electrical insulation, arc quenching and current interruption in high voltage electrical equipment. The capacity of the generator circuit breaker associated with the proposed unit will be approximately 59 pounds $SF_6$ is only used in sealed and safe systems which under normal circumstances do not leak gas; however, we account for potential emissions from this equipment in this application to be conservative.

The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. The alarm will alert operating personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of "quenching and cooling" $SF_6$ gas.

# Section 3
# Greenhouse Gas Emission Calculations

## 3.1 GHG Emissions from Combined Cycle Combustion Turbine

Combustion turbine performance and emissions are affected by ambient temperature and turbine load. Performance, exhaust and emission were developed for the combustion turbine firing natural gas at three combustion turbine steady-state loads (minimum, 75%, and 100%), three different ambient temperatures (0 °F for worst-case winter conditions, 68 °F for average annual conditions, and 112 °F for worst-case summer conditions), and for the effect of evaporative cooling based on GE's Gas Turbine Performance Simulation program. Combined cycle stack parameters and emissions that take into account HRSG duct firing are based on GE Energy's preliminary heat balance estimate for the S207FA.04 combined cycle integrated with the existing unit for design ambient conditions of 68°F and 60% relative humidity at base load with the evaporative cooling on and no duct burner. Emissions estimates and stack parameters for a total of 14 total combustion turbine steady-state operating scenarios were extrapolated from the design heat balance and presented in Appendix B, Table 1.

GHG emissions for the proposed combined cycle combustion turbine (see Table 3-1) are calculated in accordance with the procedures outlined in the Mandatory Greenhouse Gas Reporting Rules. Carbon dioxide ($CO_2$), methane ($CH_4$) and nitrous oxide ($N_2O$) emissions are calculated using the emission factors for natural gas combustion from Table C-1 and Table C-2 of 40 CFR Part 98. The global warming potential factors used to calculate carbon dioxide equivalent ($CO_2e$) emissions are based on 40 CFR Part 98, Table A-1.

## 3.2 GHG Emissions from Natural Gas Piping Fugitives and Natural Gas Maintenance and Startup/Shutdown Related Releases

GHG emission calculations for natural gas piping component fugitive emissions (see Table 3-2) are based on emission factors from Table W-1A of the Mandatory Greenhouse Gas Reporting Rules. The concentrations of $CH_4$ and $CO_2$ in the natural gas are based on a typical natural gas analysis. The global warming potential factors used to calculate $CO_2e$ emissions are based on Table A-1 of 40 CFR Part 98.

GHG emission calculations for releases of natural gas related to piping maintenance and turbine startup/shutdowns are calculated using the same $CH_4$ and $CO_2$ concentrations as natural gas piping fugitives.

Table 3-1
Annual GHG Emissions – Combustion Turbine Combined Cycle Unit

| Source | Annual Heat Input[1] (MMBtu/yr) | Pollutant | Emission Factor[2] (kg/MMBtu) | GHG Mass Emissions (tons/yr) | Global Warming Potential[3] | $CO_2$e (tons/yr) |
|---|---|---|---|---|---|---|
| Combustion turbine plus duct burner | 22,716,339 | $CO_2$ | 53.02 | 1,327,623.8 | 1 | 1,327,624 |
| | | $CH_4$ | 1.0E-03 | 25.0 | 25 | 626 |
| | | $N_2O$ | 1.0E-04 | 2.5 | 298 | 746 |
| | | GHG | Totals | 1,327,651 | | 1,328,996 |
| | | CO2e | +10% margin added for measurement error | | | 1,461,896 |

1. Annual heat input based on 8760 hours per year of operation of the combustion turbine at an average ambient temperature of 68oF with evaporative cooling on and a duct burner firing at 681.5 MMBtu/hr for 8760 hours per year.

2 $CO_2$, $CH_4$ and $N_2O$ emission factors based on Tables C-1 and C-2 of 40 CFR 98

3 Global warming potential factors based on Table A-1 of 40 CFR 98

## Example Calculations:

$$Combustion\ Turbine\ Fuel\ =\ 8760\ hr/yr\ x\ 1911.6\ MMBtu/hr\ =\ 16{,}746{,}049\ MMBtu/$$

$$Duct\ Burner\ Fuel\ =\ 8760\ hr/yr\ x\ 681.5\ MMBtu/hr\ =\ 5{,}970{,}290\ MMBtu/yr$$

$$Total\ Fuel\ =\ 16{,}746{,}049\ +\ 5{,}970{,}290\ =\ 22{,}716{,}339\ MMBtu/yr$$

Carbon Dioxide

$$22{,}716{,}339\ MMBtu/hr\ x\ (53.02\ kg\ CO2/MMBtu)\ x\ (2.2046\ lb/kg)\ /\ (2000\ lb/ton)\ x\ 1\ CO2e\ /CO2\ =\ 1{,}327{,}624\ tons\ CO2e/yr$$

Methane

$$22{,}716{,}339\ MMBtu/hr\ x\ (0.001\ kg\ CH4/MMBtu)\ x\ (2.2046\ lb/kg)\ /\ (2000\ lb/ton)\ x\ 25\ CO2e\ /CH4 =\ 626\ tons\ CO2e/yr$$

Nitrous Oxides

$$22{,}716{,}339\ MMBtu/hr\ x\ (0.0001\ kg\ N2O/MMBtu)\ x\ (2.2046\ lb/kg)\ /\ (2000\ lb/ton)\ x\ 298\ CO2e\ /N2O\ =\ 746\ tons\ CO2e/yr$$

Table 3-2
Annual GHG Emission Calculations – Natural Gas Piping

| Source | Component Type | Fluid State | Count | Emission Factor[1] scf/hr/comp | $CO_2$[2] tons/yr | $CH_4$[3] tons/yr | Total tons/yr |
|---|---|---|---|---|---|---|---|
| Additional Natural Gas Fugitives | Valves | Gas/Vapor | 194 | 0.121 | 0.093 | 4.017 | |
| | Flanges | | 161 | 0.017 | 0.011 | 0.468 | |
| | Relief Valve | | 35 | 0.193 | 0.027 | 1.156 | |
| GHG Mass Based Emissions | | | | | 0.130 | 5.642 | |
| Global Warming Potential[4] | | | | | 1 | 25 | |
| $CO_2e$ Emissions | | | | | 0.13 | 141.04 | **141.2** |

[1] Emission factors from Table W-1A of 40 CFR Part 98 Mandatory Greenhouse Gas Reporting
[2] $CO_2$ emissions based on vol% $CO_2$ in natural gas of 0.79%
[3] $CH_4$ emissions based on vol% $CH_4$ in natural gas of 94.14%
[4] Global warming potential based on Table A-1 of 40 CFR Part 98 Mandatory Greenhouse Gas Reporting

## Example Calculations:

### $CO_2$ Emissions from Valves

$$194 \text{ valves x } \left(0.121 \ \frac{\text{scf gas}}{\text{hr} - \text{valve}}\right) \text{ x } \left(0.0079 \ \frac{\text{scf CO2}}{\text{scf gas}}\right) \text{ x } \left(\frac{\text{lb} - \text{mole CO2}}{385.5 \text{ scf CO2}}\right) \text{ x } \left(44 \ \frac{\text{lb CO2}}{\text{lb} - \text{mole}}\right) \text{ x } \left(8760 \ \frac{\text{hr}}{\text{yr}}\right) \text{ x } \left(\frac{\text{ton}}{2000 \text{ lb}}\right) = 0.093 \ \frac{\text{ton CO2}}{\text{year}}$$

### $CH_4$ Emissions from Valves

$$194 \text{ valves x } \left(0.121 \ \frac{\text{scf gas}}{\text{hr} - \text{valve}}\right) \text{ x } \left(0.9414 \ \frac{\text{scf CH4}}{\text{scf gas}}\right) \text{ x } \left(\frac{\text{lb} - \text{mole CH4}}{385.5 \text{ scf CH4}}\right) \text{ x } \left(16 \ \frac{\text{lb CH4}}{\text{lb} - \text{mole}}\right) \text{ x } \left(8760 \ \frac{\text{hr}}{\text{yr}}\right) \text{ x } \left(\frac{\text{ton}}{2000 \text{ lb}}\right) = 4.017 \ \frac{\text{tons CH4}}{\text{year}}$$

## 3.3 GHG Emissions from Electrical Equipment Insulated with $SF_6$

$SF_6$ emissions from the new generator circuit breaker associated with the proposed unit (see Table 3-3) are calculated using a predicted $SF_6$ annual leak rate of 0.5% by weight per year, the IEC standard for new equipment leakage[8]. The global warming potential factors used to calculate $CO_2e$ emissions are based on Table A-1 of 40 CFR Part 98.

## 3.4 Total Project GHG Emissions

Table 3-4 summarizes total Project GHG emissions based on the sum of $CO_2e$ emissions for the proposed combined cycle unit, natural gas pipeline fugitives and SF6 emissions from the new generator circuit breaker. Emissions are speciated as $CO_2$, $CH_4$, $N_2O$ and SF6 and converted to equivalent $CO_2e$ and summed to calculate total project GHG.

[8] International Electrotechnical Commission Standard 62271-1, 2004.

Table 3-3
GHG Emission Calculations – Electrical Equipment Insulated with $SF_6$

| | |
|---|---|
| Estimated Quantity of SF6 in New Equipment | 59 pounds |
| Annual Leak Rate | 0.50% of quantity present |
| Annual Emission Rate | 0.295 lb/yr |
| Annual SF6 Emissions | 0.0001475 ton/yr of SF6 |
| Global Warming Potential Factor for SF6 | 22,800 |
| Annual CO2e Emissions | **3.36 ton/yr of CO2e** |

## Example Calculation:

$$59 \text{ lb SF6 x } \left(\frac{0.50\%}{\text{yr}}\right) \text{ x} \left(\frac{\text{ton}}{2000 \text{ lb}}\right) \text{x } 22{,}800 \; \frac{\text{CO2e}}{\text{SF6}} = \; 3.36 \; \frac{\text{tons CO2e}}{\text{yr}}$$

Table 3-4
Annual GHG Emissions - Total Project

| Source | Annual Potential Emissions, tons/year | | | | |
|---|---|---|---|---|---|
| | $CO_2$ | $CH_4$ | $N_2O$ | $SF_6$ | GHG, CO2e |
| Combined Cycle Unit (with 10% margin) | 1,460,386 | 27.5 | 2.8 | 0 | 1,461,896 |
| Natural Gas Pipeline Fugitives | 0.13 | 5.64 | 0 | 0 | 141.2 |
| Electrical Equipment Leaks | 0 | 0 | 0 | 0.00015 | 3.36 |
| Total Project | 1,460,386 | 33.2 | 2.8 | 0.0001475 | 1,462,040 |

# Section 4
# Prevention of Significant Deterioration Applicability

## 4.1 Applicability

The existing Sand Hill Energy Center is an existing major stationary source as defined under the Clean Air Act. PSD applies to GHG emissions from a proposed modification to an existing major source if the following is true:

- The emissions increase and the net emissions increase of GHGs from the modification would be equal to or greater than 75,000 tons per year on a $CO_2e$ basis and greater than zero tons per year on a mass basis.

Because the proposed Project's net emissions increase of GHG is greater than 75,000 ton/year of $CO_2e$ (see Table 3-4), PSD review is triggered for GHG emissions. The emissions netting analysis is documented on the TCEQ PSD netting tables (Table 1F and 2F) included in Appendix A.

## 4.2 Requirements

The PSD regulations state that facilities subject to PSD review must perform an air quality analysis (which can include atmospheric dispersion modeling and preconstruction ambient air quality monitoring), and BACT analysis for those pollutants that exceed the pollutant-specific significant emission rates (SERs) identified in the regulations as well as an additional impacts analysis that examines the impacts of air emissions from the project on visibility, soils and vegetation.

### 4.2.1 Best Available Control Technology

The proposed Project must utilize BACT controls for pollutants subject to PSD from each piece of new equipment. BACT is defined as the optimum level of control applied to pollutant emissions based upon consideration of energy, economic and environmental factors. In a BACT analysis, the energy, environmental, and economic factors associated with each alternate control technology are evaluated, in addition to the benefit of reduced emissions that the technology would bring. The BACT analysis for the proposed facility is detailed in Section 5.

### 4.2.2 Air Quality Impact Analysis

An impact analysis is not being provided with this application in accordance with EPA's recommendations:

*Because there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause or contribute to a violation of the NAAQS are not applicable to GHGs. Therefore, there is no requirement to conduct dispersion modeling or ambient monitoring for CO2 or GHGs.*[9]

An impact analysis for non-GHG emissions is being submitted with the State/ PSD/ Nonattainment application submitted to the TCEQ.

### 4.2.3 GHG Preconstruction Monitoring

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with EPA's recommendations:

*EPA does* not *consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts o EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for the purpose of assessing ambient air impact of GHGs.*[10]

A pre-construction monitoring analysis for non-GHG emissions is being submitted with the State/PSD/Nonattainment application submitted to the TCEQ.

### 4.2.4 Additional Impacts Analysis

A PSD additional impacts analysis is not being provided with this application in accordance with EPA's recommendations:

*Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of*

[9] EPA, *PSD and Title V Permitting Guidance For Greenhouse Gases* at 48-49
[10] *Id.* at 49

*the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyze in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges compliance with the BACT analysis is the best technique that can be employed a present to satisfy the additional impacts analysis and Class I area requirements of the rule related to GHGs.*[11]

A PSD additional impacts analysis for non-GHG emissions is being submitted with the State/PSD/Nonattainment application submitted to the TCEQ.

#### 4.2.5 Other Required Analyses

Under Section 7 of the Endangered Species Act, Section 106 of the National Historic Preservation Act and Executive Order 12898 [59 FR 7629 (February 16, 1994)], any action authorized or permitted by EPA must ensure that it will not adversely impact federally listed endangered species, historic areas and disproportionately minority or low income populations, respectively. Austin Energy has developed a Biological Assessment and Cultural Resources Survey for the proposed Project. This assessment and all relevant correspondence are included in Appendix D.

[11] Id

# Section 5
# GHG Control Technology Analysis

## 5.1 Overview

Pre-construction review for new major stationary sources involves an evaluation of BACT. The BACT methodology presented herein is based on USEPA's recommended "top-down," 5-step analysis process to evaluate the available and applicable emission control technologies for the affected pollutants. BACT as defined in 40 CFR Part 52.21(b)(12) is:

*"An Emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant."*

At the head of the list in the top-down analysis are the control technologies and emissions limits that represent the Lowest Achievable Emission Rate (LAER) determinations, which, under NSR/PSD regulations, represent the most effective control alternative and must be considered under the BACT analysis process. BACT cannot be determined to be less stringent than the emission limits established by an applicable New Source Performance Standard (NSPS) for the affected air emission source, but no NSPS limit has been finalized for GHG emissions from utility sources. The methodology uses a 5-step process, which is summarized below.

### Step 1: Identify All Control Technologies

The first step in a "top-down" analysis is to identify all available control options, including lower emitting processes, practices, and post-combustion controls.

### Step 2: Eliminate Technically Infeasible Options

The second step of the "top-down" analysis is to eliminate the technically infeasible control options from those identified in Step 1, including options that have not been "demonstrated"; or more specifically, a technology that has not been installed and operated successfully on a similar type of unit of comparable size. Technologies that are in development and testing stages are classified as not available and therefore infeasible.

### Step 3: Rank Remaining Control Technologies by Control Effectiveness

The third step of the "top-down" analysis is to rank all the remaining (feasible) control alternatives based on their control effectiveness. The following informational databases, clearinghouses, documents, and studies were used to identify recent control technology determinations for similar source categories and emission units:

- USEPA's RACT/BACT/LAER Clearinghouse (RBLC)
- Federal/State/Local new source review permits
- Technical journals, newsletters, and reports
- Information from air quality control technology suppliers
- Engineering design studies for this and similar units

### Step 4: Evaluate Most Effective Controls

The additional evaluations of feasible controls consider and compare the energy, environmental, and economic impacts associated with implementing the viable control alternatives. The economic impact analysis is performed to assess the cost to purchase and operate the control technology. The capital cost and operating/annual costs are estimated and a total equivalent annualized cost ($/year) is divided by the quantity of pollutant removed (tons/year) to calculate the cost effectiveness ($/ton) of a control technology.

### Step 5: Select BACT

The highest ranked control technology from Step 3 that is not eliminated in Step 4 based on unacceptable economic, energy, or environmental impacts, is proposed as BACT for the pollutant and emission unit under review.

## 5.2 BACT Analysis for Greenhouse Gas (GHG) Emissions

As described in Section 3, the sources of GHG emissions for the proposed Project include the new combined cycle combustion turbine/duct burner, natural gas pipeline fugitives and electrical equipment insulated with $SF_6$.

### 5.2.1 BACT Analysis for Combined Cycle Unit

#### *5.2.1.1 Identification of GHG Control Options*

A search of the RBLC for "carbon dioxide" did not yield any results for combined cycle combustion turbines; however, Austin Energy is aware of several projects which have recently been permitted with GHG emission limits. These facilities are identified in Table 5-1 below.

Table 5-1
Summary of GHG Permit Emission Limits for Combined Cycle Units

| Facility | State | Combustion Turbine Manufacturer / Model | Permit Status | Combined Cycle GHG BACT Limits | | Simple Cycle |
|---|---|---|---|---|---|---|
| | | | | Combined Cycle Output Basis lb CO2e / MWh | Combined Cycle Heat Rate Btu/kWh (HHV) | Estimated Simple Cycle Heat Rate, Btu/kWh (HHV)* |
| Russell City | CA | Siemens 501F | Final | | 7,730 | 10,385 |
| Pacificorp | UT | Siemens 5000F | Final | 950 | | 10,385 |
| LCRA Ferguson | TX | GE 7FA | Final | 918 | 7,720 | 10,009 |
| Kennecott | UT | GE 7FA | Final | | 7,642 | 10,009 |
| Pioneer Valley | MA | Mitsubishi 501G | Final | 895 | | |
| CPV Valley | NY | Siemens 5000F | Draft | 925 | | 10,385 |
| CPV Woodbridge | NJ | GE 7FA | Final | 925 | 7,605 | 10,009 |
| Cricket Valley | NY | GE 7FA | Final | 913** | 7,605 | 10,009 |
| Hess Newark | NJ | GE 7FA | Final | 887 | 7,522 | 10,009 |
| Calpine Deer Park | TX | Siemens 501F | Final | 920 | 7,730 | 10,385 |
| Calpine Channel | TX | Siemens 501F | Final | 920 | 7,730 | 10,385 |

*Representative base load simple cycle (combustion turbine only) heat rate for model of combustion turbine used / not project-specific data or permit limit

**No output-based (lb CO2e/MWh) limit in permit, but this lb CO2e/MWh value is calculated based on permit limits on heat rate (Btu/kWh) and emission factor (lb/MMBtu):

$$\text{lb CO2e/MWh} = \text{lb CO2e/MMBtu} \times \text{Btu/kWh} \times 10^3 \text{ kWh/MWh} \times \text{MMBtu}/10^6 \text{ BTU}$$

Additional details on these combined cycle facility permits and limits are provided in Appendix C, Table 1.

Based on engineering knowledge and judgment and permit applications submitted to EPA Region 6 for similar facilities, the following potentially applicable GHG control technologies were evaluated:

- Carbon Capture and Storage
- Electrical Generation Efficiency

*Carbon Capture and Storage (CCS)*

Capture and compression, transport, and geologic storage of the $CO_2$ is a post-combustion technology that is not considered commercially viable for natural gas combustion sources at this time. However, because EPA Region 6 has requested consideration of CCS by other GHG permit applicants, CCS is evaluated further in this analysis including an evaluation of its cost-effectiveness. CCS systems involve the use of adsorption or absorption processes to remove $CO_2$ from flue gas, with subsequent desorption to produce a concentrated $CO_2$ stream. The concentrated $CO_2$ is then compressed to supercritical temperature and pressure, a state in which $CO_2$ exists as neither a liquid nor a gas, but instead has physical properties of both liquids and gases. The supercritical $CO_2$ would then be transported to a location that allows for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR).

*Electrical Generation Efficiency*

Other than capture and sequestration of GHG emitted by combustion, the only known option for reducing GHG emissions from natural gas combined cycle units is through maximization of the energy released during the combustion process and then through the maximization of the use or capture of that energy. To minimize GHG emissions, it is desirable to use less fuel to generate a given amount of electrical energy. There are several factors that may affect the amount of GHG produced per MW-hour of energy produced. These include low carbon fuels and the thermodynamic and mechanical efficiency of the combustion unit.

#### *5.2.1.2 Elimination of Technically Infeasible Alternatives*

All options identified above are considered "technically" feasible for the purposes of this BACT analysis.

#### 5.2.1.3 Ranking of Remaining Technologies Based on Effectiveness

Both CCS and electrical generation efficiency are considered "technically" feasible and are ranked in order of desirability below:

1. Carbon Capture and Storage (CCS)
2. Electrical Generation Efficiency

#### 5.2.1.4 Evaluation of Control Technologies

The energy, environmental, and economic feasibility of implementing the different control technologies as BACT for GHG emissions from the proposed Project's gas turbine/HRSG train are evaluated below for the two technically feasible control technologies:

1. Carbon Capture and Storage (CCS)
2. Electrical Generation Efficiency

*Carbon Capture and Storage (CCS)*

Each component of CCS technology (i.e., capture and compression, transport, and storage) is discussed separately. These include:

1. Carbon Capture and Compression
2. $CO_2$ Transport
3. $CO_2$ Storage

*Carbon Capture and Compression*

Although amine absorption technology for $CO_2$ capture has been applied to processes in the petroleum refining and natural gas processing industries and to exhausts from gas-fired industrial boilers, it is more difficult to apply to power plant gas turbine exhausts, which have considerably larger flow volumes and considerably lower $CO_2$ concentrations (partial pressures). The Obama Administration's Interagency Task Force on Carbon Capture and Storage confirms this in its recently completed report on the current status of development of CCS systems:

*"Current technologies could be used to capture $CO_2$ from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the $CO_2$ capture capacities used in current industrial processes are generally much smaller than the capacity*

*required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."*[12]

In its current CCS research program plans, the Department of Energy's National Energy Technology Laboratory (DOE-NETL) confirms that commercial $CO_2$ capture technology for large-scale power plants is not yet available and suggests that it may not be available until at least 2020:

*"The overall objective of the Carbon Sequestration Program is to develop and advance CCS technologies that will be ready for widespread commercial deployment by 2020." To accomplish widespread deployment, four program goals have been established:*

1. *Develop technologies that can separate, capture, transport, and store CO2 using either direct or indirect systems that result in a less than 10 percent increase in the cost of energy by 2015;*
2. *Develop technologies that will support industries' ability to predict CO2 storage capacity in geologic formations to within ±30 percent by 2015;*
3. *Develop technologies to demonstrate that 99 percent of injected CO2 remains in the injection zones by 2015;*
4. *Complete Best Practices Manuals (BPMs) for site selection, characterization, site operations, and closure practices by 2020. Only by accomplishing these goals will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020 and through the next several decades."*[13]

The partial pressure for $CO_2$ in a natural gas combined cycle flue gas is much lower than the partial pressure of $CO_2$ in a coal-fired boiler flue gas: the volume of $CO_2$ in a natural gas combined cycle stack is typically 3-5% compared to 11-12% in a coal fired boiler stack flue gas.

Most carbon capture research and trials to date feature the amine absorption process for coal fired power plants, because the flue gas has a much higher $CO_2$ partial pressure in a coal boiler. Other disadvantages of the amine process that have not been fully addressed are the following:

1. The high concentration of oxygen in the natural gas turbine stack adversely affects solvents such as amine.
2. The amine processes also tend also to be prohibitively expensive, for one because of the cooling that is required to remove sulfur and nitrogen compounds that may potentially poison the solvent.

[12] *Report of the Interagency Task Force on Carbon Capture and Storage* at 50 (Aug. 2010).
[13] DOE-NETL, *Carbon Sequestration Program: Technical Program Plan,* at 10 (Feb. 2011).

Significant research conducted by Mitsubishi Heavy Industries (MHI) has demonstrated both the advantage of inhibited amine technology and the significantly greater cost and difficulty for removal of CO2 from gas turbines as compared to coal boilers. Further support for the conclusion that commercial availability of $CO_2$ capture technology for large-scale power plant projects will not occur for several more years was found by reviewing information published by Alstom, a major developer of commercial $CO_2$ capture technology using post-combustion amine absorption, post-combustion chilled ammonia absorption and oxy-combustion. Alstom states on its web site that its $CO_2$ capture technology will become commercially available in 2015.[14] However, it should be noted that in committing to this timeframe, the company does not indicate whether such technology will be able to handle the volume of $CO_2$ emissions generated by a project the size of this proposed project.

Conservation of water resources is another important challenge associated with $CO_2$ capture. A modern natural gas fired combined cycle facility requires four to five million gallons of water per day for condenser cooling and boiler make-up service. This amount will vary based on ambient temperature and humidity as well as the level of duct firing in the HRSG. Adding $CO_2$ separation facilities and compression equipment significantly increases the cooling water requirements of a generating station. Studies indicate that the water consumption of a natural fired combined cycle facility with CCS may have an increased water consumption of more than 60%.[15]

### *$CO_2$ Transport*

Even if it is assumed that $CO_2$ capture and compression could feasibly be achieved for the proposed Project, the high-volume $CO_2$ stream generated would need to be transported to a facility capable of storing it. Potential geologic storage sites in Texas, Louisiana, and Mississippi to which $CO_2$ could be transported if a pipeline was constructed are illustrated in Figure 5-1. The potential length of such a $CO_2$ transport pipeline cannot be determined because no sites can be identified that are suitable for large-scale, long-term $CO_2$ storage. However, Denbury Resources (Denbury) operates a $CO_2$ pipeline in southeast Texas, called the "Green Pipeline". Debury will purchase high purity $CO_2$ from companies and will use the $CO_2$ for enhanced oil recovery (EOR). The nearest location for delivery to the Green Pipeline is in the Hastings oil field southeast of Houston. The distance to the Hastings oil field is 135 miles. In order to get $CO_2$ from SHEC to the Green Pipeline Austin energy would have to construct a 135 mile pipeline.

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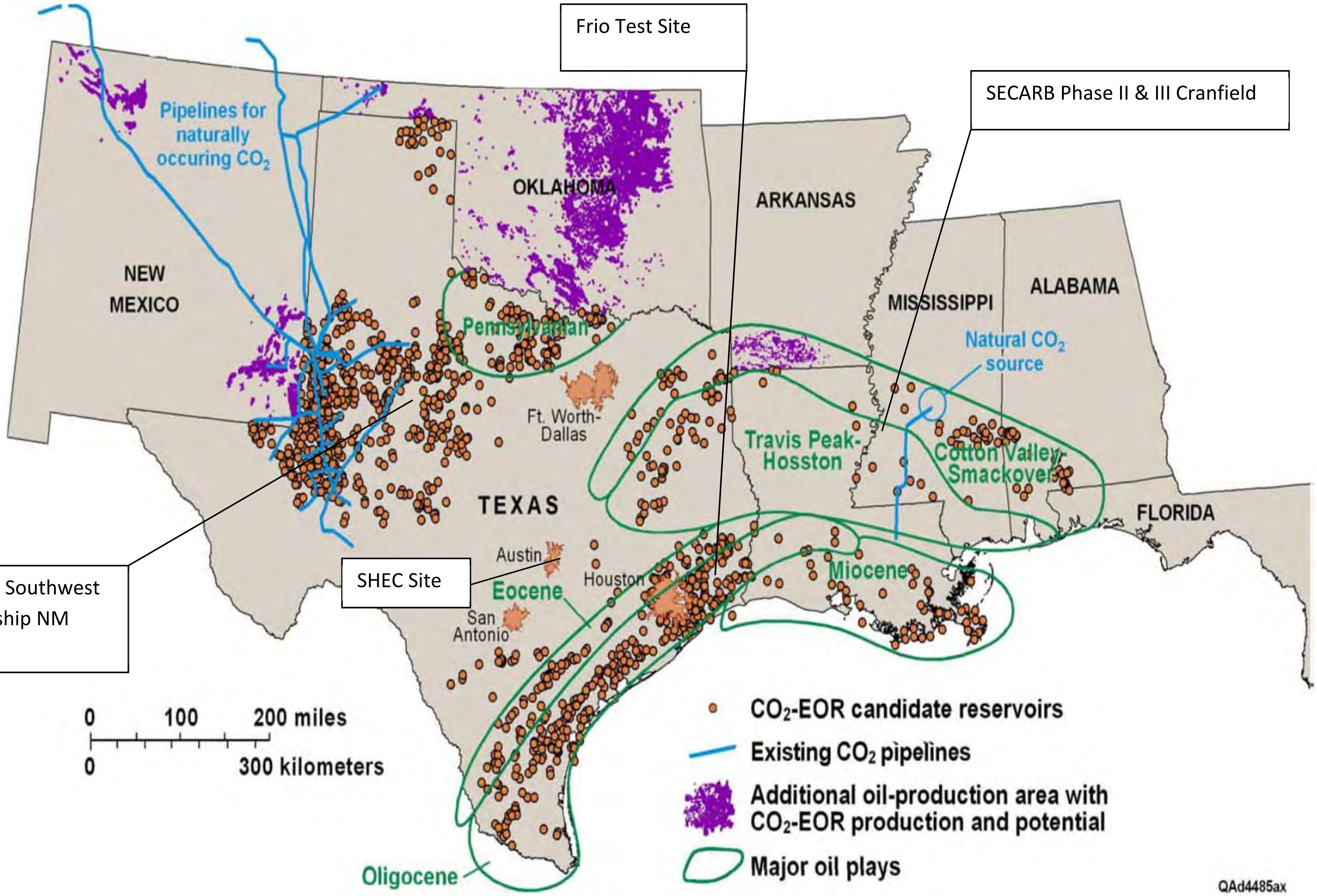
[14] Alstom, *Alstom's Carbon Capture Technology Commercially "Ready to Go" by 2015*, Nov. 30, 2010, http://www.alstom.com/australia/news-and-events/pr/ccs2015/
[15] *Report of the Interagency Task Force on Carbon Capture and Storage* at 50 (Aug. 2010).

**Figure 5-1: Potential $CO_2$ Storage Areas and Existing $CO_2$ Pipelines**




*Source: University of Texas at Austin Bureau of Economic Ecology, Gulf Coast Carbon Center*

### $CO_2$ Storage

Even if it is assumed that $CO_2$ capture and compression could feasibly be achieved for the proposed project and that the $CO_2$ could be transported economically, the feasibility of CCS technology would still depend on the availability of a suitable sequestration site. The suitability of potential storage sites is a function of volumetric capacity of their geologic formations, $CO_2$ trapping mechanisms within formations (including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock), and potential environmental impacts resulting from injection of $CO_2$ into the formations. Potential environmental impacts resulting from $CO_2$ injection that still require assessment are significant unknown risks before CCS technology can be considered feasible include:

- Uncertainty concerning the significance of dissolution of $CO_2$ into brine,
- Risks of brine displacement resulting from large-scale $CO_2$ injection, including a pressure leakage risk for brine seeping into underground drinking water sources and/or surface water,
- Risks to fresh water as a result of leakage of $CO_2$, including the possibility for damage to the biosphere, underground drinking water sources, and/or surface water,[16]
- Potential effects on wildlife, and
- Risk of metals leaking from underground formations as a result of the injection of acid gases.

Potentially suitable storage sites, including EOR sites and saline formations, exist in Texas, Louisiana and Mississippi. As was discussed above, the nearest location where the infrastructure exists in the Hastings oil field 135 miles away from SHEC.

Based on the reasons provided above, the City of Austin believes that CCS technology should be eliminated from further consideration as a potential feasible control technology for purposes of this BACT analysis. However, to answer possible questions that the public or the EPA may have concerning the relative costs of implementing hypothetical CCS systems, the City of Austin has estimated such costs.

### Cost and Energy Impacts of Carbon Capture and Storage

The estimated costs associated with implementation of a carbon capture system for the proposed Project are shown in Table 5-2 below. Capital cost components include equipment

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[16] Susan Hovorka, University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, *New Developments: Solved and Unsolved Questions Regarding Geologic Sequestration of CO2 as a Greenhouse Gas Reduction Method* (GCCC Digital Publication #08-13) at slide 4 (Apr. 2008), available at: http://www.beg.utexas.edu/gccc/forum/codexdownloadpdf.php?ID=100

(complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management and contingencies. Operating cost components include operating and maintenance labor, consumables, fuel, waste disposal and co-product or by-product credit.

The capital cost of a $CO_2$ capture system for SHEC would be approximately $170 million[17]. Based on an estimated project capital cost for the addition of a CTG and HRSG of $195 million, the addition of the CO2 capture portion of CCS control scheme would be expected to add 87% to the project's overall capital cost. The capital cost for the pipeline that would be required to transport the CO2 to a suitable storage site is estimated to be another $238 million.

In addition to the high construction and operating costs associated with CCS, the carbon capture equipment requires a substantial amount of energy to operate, thereby reducing the net electrical output of the plant. Operation of carbon capture equipment at a typical natural gas fired combined cycle plant is estimated to reduce the net energy efficiency of the plant from approximately 50% to approximately 42.9%.[18]

The capital cost to construct a suitable 135-mile pipeline to the nearest site with any potential for geological storage of $CO_2$ is calculated to be greater than $238 million (Appendix C, Table 2) per pipeline cost equations developed by DOE-NETL.[19]

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[17] *Report of the Interagency Task Force on Carbon Capture and Storage* (Aug. 2010).

[18] US Department of Energy, National Energy Technology Laboratory, "Costs and Performance Baseline For Fossil Energy Plants, Volume 1 - Bituminous Coal and Natural Gas to Energy", Revision 2, November 2010

[19] Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs, National Energy Technology Laboratory, US Department of Energy, DOE/NETL-2010/1447 (March, 2010)

Table 5-2
CCS Cost Analysis for Combined Cycle Unit

| CCS System Component | Capital Cost[1] ($) (1) | Annual Cost [1] ($/ton) (2) | $CO_2$ Removed[3] (ton/yr) (3) | Total Annualized Cost[4] ($/year) (2) * (3) |
|---|---|---|---|---|
| $CO_2$ Capture & Compression Facilities | $170,000,000 | $103 | 1,314,348 | $135,928,752 |
| $CO_2$ Transport Facilities | $238,205,778 | $18.00[2] | 1,314,348 | $23,651,945 |
| $CO_2$ Storage Facilities | NA[5] | $0.51 | 1,314,348 | $667,720 |
| Total CCS System Cost | > $408,000,000 | $122 | 1,314,348 | $160,248,417 |
| Potential Revenue from Sale of $CO_2$ for EOR[6] | | ($23) | 1,314,348 | ($30,229,994) |
| **Total CCS System Cost with Sale of $CO_2$ for EOR** | | **$99** | 1,314,348 | **$130,018,423** |

1. $CO_2$ capture/compression and storage costs are from Report of the Interagency Task Force on Carbon Capture (August, 2010). Cost includes initial investment, O&M, and cost of fuel.
2. $CO_2$ transport cost is calculated per pipeline cost equations from Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs, National Energy Technology Laboratory, US Department of Energy, DOE/NETL-2010/1447 (March, 2010). See Appendix Table 2
3. Tons of $CO_2$ removed assumed 90% capture of all $CO_2$ emissions from the combustion turbine and duct burner.
4. Annualized costs based on 7% interest rate and 20 year equipment life
5. No capital cost estimate provided for CO2 storage in Report of the Interagency Task Force on Carbon Capture (August, 2010)
6. US price from sale of $CO_2$ for Enhanced Oil Recovery (EOR) is $10-40/tonne, from http://www.globalccsinstitute.com/publications/global-status-ccs-2012/online/48431

## Example Calculations (Total Annualized Cost):

$$\text{Capture \& Comp:} \left(\frac{\$103}{\text{ton}}\right) \text{x} \left(\frac{1{,}314{,}348 \text{ ton CO2}}{\text{yr}}\right) = \frac{\$135{,}928{,}752}{\text{yr}}$$

$$\text{CO2 Transport:} \left(\frac{\$18.00}{\text{ton}}\right) \text{x} \left(\frac{1{,}314{,}348 \text{ ton CO2}}{\text{yr}}\right) = \frac{\$23{,}651{,}945}{\text{yr}}$$

$$\text{CO2 Storage:} \left(\frac{\$0.51}{\text{ton}}\right) \text{x} \left(\frac{1{,}314{,}348 \text{ ton CO2}}{\text{yr}}\right) = \frac{\$667{,}720}{\text{yr}}$$

Total CCS System Cost: $\left(\frac{\$135,928,752}{\text{yr}}\right)+\left(\frac{\$23,561,945}{\text{yr}}\right)+\left(\frac{\$667,720}{\text{yr}}\right)=\frac{\$144,597,870}{\text{yr}}$

Based on the same guidance, the annual pipeline O&M cost would be more than $1,165,320/year, and the total annual cost including annualized capital cost would be about $23.7 million per year. A cost is also associated with the monitoring and maintenance of the $CO_2$ storage facility. The total equivalent annual cost for all aspects of the site-specific CCS option total about $160 million/year. Assuming the system would capture 90% of the combined cycle unit $CO_2$, the cost effectiveness is calculated at $122/ton $CO_2$. Assuming that all of the CO2 captured could be sold for use in Enhanced Oil Recovery (EOR), a $23/ton credit has been applied in the cost analysis, reducing the net cost of CCS to $99/ton $CO_2$.

### Electrical Generation Efficiency

The following energy efficiency practices are associated with and incorporated into the proposed combined cycle unit design:

#### Use of Low Carbon Fuel

The first aspect to evaluate with regard to an energy efficient process is the source of fuel. 40 CFR part 98 provides emission factors for GHG from the combustion of various fuels. Natural gas is listed as the third cleanest fuel with respect to $CO_2$ emissions, the third cleanest fuel with respect to $CH_4$ emissions and the cleanest fuel with respect to $N_2O$ emissions. The two cleaner fuels with respect to $CO_2$ emissions (coke oven gas and biogas) are not feasible sources of fuel for the project based on the need to match the technology choice (natural gas turbine) to the existing combined cycle unit. Therefore, with regard to fuels that can be utilized by the project, natural gas produces the lowest GHG emissions profile.

#### Turbine Design/Selection

In a combined cycle configuration, a HRSG is used to recover what would otherwise be waste heat lost to the atmosphere in the hot turbine exhaust. Use of heat recovery from the turbine exhaust to produce steam to power a steam turbine which generates additional electric power is the single most effective means of increasing the efficiency of combustion turbines used for electric power generation. The overall thermal efficiency for the proposed project is increased from about 39% for the simple cycle combustion turbine (no heat recovery) unit to about 59% for the unit in combined cycle configuration including electricity generated in the STG. In applications where process heat is needed, the steam produced in the HRSG can also be used to provide heat to plant processes in addition to or instead of being used to produce additional electricity. This “cogeneration” technology is not applicable to electric power generation unless there is a co-located steam host or other means of using additional recoverable waste heat.

The existing combined cycle unit at SHEC is operating in a 1 x 1 configuration with a GE 7FA gas turbine with a 164 MW (nominal at ISO) generator, a HRSG, and a GE D-11 steam turbine with a 189 MW generator. Not all of this STG capacity can be utilized with only the existing CTG/HRSG, even with the duct burner firing at maximum design capacity. Ultimate expansion of the unit to a 2 x 1 configuration was part of the original design and the existing steam turbine and cooling tower were sized for a second 7FA and associated HRSG.

In evaluating different turbines, SHEC decided that a second 7FA provided benefits from an operations and maintenance perspective that other turbines models did not. SHEC plant staff is experienced in operating and maintaining the 7FA and the addition of a second 7FA would minimize changes to the control system, operating procedures and training. A second 7FA would also simplify maintenance by leveraging staff experience as well as reduce the quantity and cost of spare parts which would be required to maintain two different gas turbines. Estimated cost savings associated with selection of a second GE 7FA unit versus a different turbine model are:

- Operation training: $300,000
- Control system integration: $3,000,000 (exclusive of engineering and design changes and commissioning complications)
- Spare combustion parts: $3,000,000 to $5,000,000
- Long Term Service Agreement (LTSA): $3,000,000 to $4,000,000 (incremental)

A newer version of the GE 7FA turbine is now available that allows for a higher firing temperature and therefore improvements in output and heat rate (i.e., greater thermal efficiency). The output of the existing GE 7FA.03 CTG is 161.5 MW at full load at the site ambient average temperature of 68°F and the GE 7FA.04 output is 200 MW at ISO conditions. Although there would be advantages for SHEC to have identical GE 7FA.03 turbines at the facility, the improved performance of the 7FA.04 will make the overall efficiency of the combined cycle unit with the shared STG better and thereby reduce the GHG emissions in terms of CO2e/MWh of electricity generated.

Heat rate (Btu/kWh) values are provided for the combustion turbine alone (simple cycle) and in combination with the HRSG/STG output (combined cycle) for each of the 14 operating modes modeled for the proposed new unit in the spreadsheet of performance and emissions data provided in Appendix B, Table B-1, and summarized in Table 5-3 below. Example calculations for heat rates are provided in the footnotes to Table B-1.

Table 5-3
Estimated Performance and Emissions for GE 7FA.04 Combustion Turbine in Simple Cycle and Combined Cycle Mode

| oad Condition | % CTG Base Load | **BASE** | **BASE** | **75%** | **50%** | **BASE** | **BASE** | **BASE** | **75%** | **53%** | **BASE** | **BASE** | **BASE** | **75%** | **69%** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| mbient Temperature | deg F | **0** | **0** | **0** | **0** | **68** | **68** | **68** | **68** | **68** | **112** | **112** | **112** | **112** | **112** |
| vap. Cooler Status | | Off | Off | Off | Off | **On** | **On** | Off | Off | Off | **On** | **On** | Off | Off | Off |
| vap. Cooler Effectiveness | % | 0 | 0 | 0 | 0 | 85 | 85 | 0 | 0 | 0 | 85 | 85 | 0 | 0 | 0 |
| uct Burner Status | | **On** | Off | Off | Off | **On** | Off | Off | Off | Off | **On** | Off | Off | Off | Off |
| mbient Relative Humidity | % | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 |
| let Loss | in H2O | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| xhaust Pressure Loss | in H2O | 16.1 | 16.1 | 10.7 | 7.3 | 14.4 | 14.4 | 14 | 9.5 | 7 | 11.5 | 11.5 | 10.7 | 8 | 7.4 |
| TG Output (Simple Cycle) | kW | 196,178 | 196,178 | 147,133 | 98,089 | 179,025 | 179,025 | 173,910 | 130,433 | 92,172 | 152,206 | 152,206 | 142,802 | 107,101 | 98,533 |
| TG Output (estimated)* | kW | 168,683 | 102,365 | 86,067 | 74,672 | 162,271 | **95,953** | 94,620 | 80,141 | 71,053 | 153,844 | 87,526 | 85,269 | 75,042 | 72,240 |
| C (CTG + STG) Combined Cycle Output | kW | 364,861 | 298,543 | 233,200 | 172,761 | 341,296 | 274,978 | 268,530 | 210,574 | 163,225 | 306,050 | 239,732 | 228,071 | 182,143 | 170,773 |
| TG Simple Cycle Heat Rate (HHV) | BTU/kWh, HHV | 9,744 | 9,744 | 10,462 | 12,470 | 9,964 | 9,964 | 10,020 | 10,823 | 12,611 | 10,454 | 10,454 | 10,639 | 11,825 | 12,199 |
| TG Simple Cycle Heat Rate, HHV (+ margin**) | BTU/kWh, HHV | 10,718 | 10,718 | 11,508 | 13,717 | 10,961 | 10,961 | 11,022 | 11,906 | 13,872 | 11,500 | 11,500 | 11,703 | 13,008 | 13,419 |
| ombined Cycle (CTG + STG) Heat Rate (HHV) | BTU/kWh, HHV | 7,104 | 6,403 | 6,601 | 7,080 | 7,221 | 6,488 | 6,489 | 6,704 | 7,121 | 7,422 | 6,637 | 6,662 | 6,953 | 7,038 |
| ombined Cycle (CTG + STG) Heat Rate (+ margin**) | BTU/kWh, HHV | 7,815 | 7,044 | 7,261 | 7,788 | 7,943 | 7,136 | 7,138 | 7,375 | 7,833 | 8,165 | 7,301 | 7,328 | 7,648 | 7,742 |
| TG Heat Consumption (HHV) | MMBTU/hr | 1,911.6 | 1,911.6 | 1,539.4 | 1,223.2 | 1,784.0 | 1,784.0 | 1,742.4 | 1,411.7 | 1,162.4 | 1,591.1 | 1,591.1 | 1,519.4 | 1,266.4 | 1,201.9 |
| O2 | lb/hr | 303,110 | 223,447 | 179,934 | 142,976 | 288,187 | 208,524 | 203,666 | 165,011 | 135,864 | 265,647 | 185,984 | 177,602 | 148,028 | 140,488 |
| O2 | lb/MMBTU, HHV | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 |
| 2O | lb/hr | 0.6 | 0.4 | 0.3 | 0.3 | 0.5 | 0.4 | 0.4 | 0.3 | 0.3 | 0.5 | 0.4 | 0.3 | 0.3 | 0.3 |
| 2O | lb/MMBTU, HHV | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 |
| H4 | lb/hr | 5.7 | 4.2 | 3.4 | 2.7 | 5.4 | 3.9 | 3.8 | 3.1 | 2.6 | 5.0 | 3.5 | 3.3 | 2.8 | 2.6 |
| H4 | lb/MMBTU, HHV | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 |
| HG, CO2e | lb/hr | 303,408 | 223,666 | 180,110 | 143,116 | 288,470 | 208,728 | 203,866 | 165,173 | 135,997 | 265,907 | 186,166 | 177,776 | 148,173 | 140,626 |
| HG, CO2e | lb/MMBTU, HHV | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 |
| HG, CO2e (Simple Cycle) | ton/MWh | 0.773 | 0.570 | 0.612 | 0.730 | 0.806 | 0.583 | 0.586 | 0.633 | 0.738 | 0.874 | 0.612 | 0.622 | 0.692 | 0.714 |
| HG, CO2e (Simple Cycle + margin**) | ton/MWh | 0.851 | 0.627 | 0.673 | 0.802 | 0.886 | 0.641 | 0.645 | 0.696 | 0.812 | 0.961 | 0.673 | 0.685 | 0.761 | 0.785 |
| HG, CO2e (Combined Cycle) | ton/MWh | 0.416 | 0.375 | 0.386 | 0.414 | 0.423 | 0.380 | 0.380 | 0.392 | 0.417 | 0.434 | 0.388 | 0.390 | 0.407 | 0.412 |
| HG, CO2e (Combined Cycle + margin**) | ton/MWh | 0.457 | 0.412 | 0.425 | 0.456 | 0.465 | 0.417 | 0.418 | 0.431 | 0.458 | 0.478 | 0.427 | 0.429 | 0.447 | 0.453 |

STG output (kW) estimated by scaling from design case (68 F, evap cooler on, unfired) based on ratio of exhaust energy + duct burner heat input to design case exhaust energy; actual STG output limited to 148 MW with only 1 CTG perating, but maximum duct burner firing rate used for all conditions as worst case for permitting

Margin added for measurement error, off-design conditions and degradation 10.0%

xample Calculations provided in Appendix B, Table 1

Simple cycle gross heat rates range from 10,718 to 11,703 Btu/kWh (HHV) at full load without evaporative cooling. Combined cycle heat rates are estimated to range from 7,044 to 7,328 Btu/kWh (HHV) for these same operating conditions[20]. Heat rates are higher (efficiency lower) at higher ambient temperatures and lower turbine loads. The use of evaporative cooling improves the heat rate by lowering the compressor inlet temperature. Use of the duct burners to increase steam production in the HRSG and STG output increases the overall combined cycle heat rate.

It is worth noting that the outputs and heat rates identified above are based on the specific turbine design and performance for this project at the SHEC site. Thus it is likely that these values may differ somewhat from those published in the manufacturer's literature or website summarizing performance for a variety of combustion turbine manufacturers and models. Factors that influence the output and heat rate from project to project include ambient temperature, humidity and site elevation; fuel type/composition and exhaust back pressure (due to the HRSG, catalysts and the length of the flue gas path – or stack height) will also have a significant impact on performance. The combined cycle heat rate of the proposed unit compares favorably to the heat rate limits included in recent permits for other GE 7FA units, as well as combined cycle units with other GE turbine models and those of other manufacturers, which are summarized in Table 5-1. Most of these permits have minimum combined cycle heat rate limits in the range of 7,522 to 7,730 Btu/kWh, HHV.

GHG emission limits for units comparable to the proposed SH8 unit that have output-based lb/MWh and or heat rate (Btu/kWh) basis limits are extracted from the comprehensive list in Appendix C and summarized in Table 5-1 above.

#### *5.2.1.5 Determination of BACT for Combined Cycle Unit*

The City of Austin (dba Austin Energy) proposes as BACT for this project, the following energy efficiency processes, practices, and designs for the proposed combined cycle combustion turbine:

- Use of Combined Cycle Power Generation Technology
- Use of natural gas as the exclusive fuel
- Efficient turbine design

[20] SH8 combined cycle heat rates are based on STG outputs extrapolated from the design (full load at 68 degrees F) case used to model the performance for a 2-on-1 configuration with the existing SH5 unit; in some cases with duct firing the STG output is greater than it can actually be in order to evaluate maximum duct burner firing rates.

The proposed GE 7FA.04 combustion turbine is the most efficient unit available that is suitable for incorporation into the existing combined cycle unit as described above, with a gross heat rate at base load ranging from 9,744 to 10,639 Btu/kWh, HHV, at base load without evaporative cooling, depending on ambient conditions (refer to Table 5-3). For comparison, the existing SH5 unit combustion turbine, as GE 7FA.03 model, has a heat rate ranging from 10,004 to 11,055 Btu/kWh, HHV, across the same range of conditions, so the newer model is about 3 to 4% more efficient, translating to 3 to 4% lower GHG emissions. Other manufacturers have made similar improvements: a chief competitor to the GE 7FA, the Siemens 5000F (Westinghouse 501F) turbine; has improved simple cycle efficiency from approximately by approximately 4% over the last 20 or so years. In combined cycle mode, with the benefit of the HRSG and additional output from the STG, the gross heat rate of the proposed GE 7FA.04 unit is expected range to from 7,044 to 7,328 Btu/kWh, HHV without evaporative cooling.

Because the new combustion turbine will be added to an existing combined cycle unit and its HRSG will provide steam to a steam turbine generator that is shared with the existing turbine, it is not possible to determine a combined cycle heat rate standard and output-based GHG limit that is separate from the performance of the existing SH5 turbine and HRSG performance. The SH5 unit was permitted prior to GHG BACT requirements and as such has no GHG emission limit or heat rate limit in its permit conditions. Therefore, the City of Austin is proposing GHG BACT limits based on the new combustion turbine alone (simple cycle basis) without duct burner firing:

- Simple cycle output-based GHG limit of <u>0.81 ton $CO_2e$/MWh</u> combustion turbine gross output basis; equivalent to 0.458 ton $CO_2e$/MWh (or 916 lb/MWh) gross output basis for the combined cycle unit that shares the STG with the existing SH5 combustion turbine, with unfired HRSG
- Simple cycle combustion turbine gross output heat rate of <u>13,872 Btu/kWh (HHV)</u>; equivalent to 7,833 BTU/kWh (HHV) gross heat rate for the combined cycle unit that shares the STG with the existing SH5 combustion turbine, at 68°F with unfired HRSG

The proposed output-based GHG emission limits are equivalent to the most recent GHG permit limits for similar combined cycle units as summarized in Table 5-1 (approximately 0.466 ton CO2e/MWh or 932 lb/MWh, combined cycle basis) and the proposed heat rate limit is comparable to the most recent limits for similar units.

As with other recent GHG permits for combined cycle units, compliance with these performance standards is determined for operation at 100% load at ISO conditions, without evaporative cooling or duct burner firing. This provides a standard basis for comparison of the GHG limits that are permitted for different projects. In order to demonstrate that the proposed simple cycle GHG limit corresponds to the combined cycle performance indicated above, the

City of Austin proposes to perform the initial compliance test with only the new combined cycle unit operating (i.e., with SH5 off line). In order to regulate GHG emissions from all operating conditions, including those using evaporative cooling and with duct burner firing, the City of Austin is also proposing a GHG BACT limit on total annual GHG emissions for the combined cycle combustion turbine and duct burner:

- Annual emission cap of 1,461,896 tons $CO_2e$ per year, for the addition of the second combustion turbine, HRSG and duct burner

The proposed GHG BACT limits for the proposed new unit are summarized in Table 5-4 below.

This approach of a combination of output based $CO_2e$ limits and heat rate limits at standard conditions and an annual emission cap to cover other operating conditions and emissions has been used in other recent GHG BACT permit limits for combined cycle units.

Each of the proposed limits is calculated to include a 10% margin to account for measurement error, equipment and site variations, and degradation over time.

Compliance with the output based emission limits will be based on a 30-day rolling average. Compliance with the annual tons/year limit will be based on a rolling 365-day total. In each case, SHEC proposes to calculate GHG emissions based on continuous monitoring of the fuel flow to the combustion turbine and duct burner using calibrated fuel flow meters, with heat input calculated based on weighted average monthly heating values provided by the pipeline natural gas supplier, and emissions of $CO_2e$ calculated based on emission factors and GWPs from 40 CFR 98 (greenhouse gas monitoring rule). Gross output (kW) will be continuously measured and recorded at the combustion turbine generator.

### 5.2.2 BACT Analysis for Natural Gas Fugitives

Small amounts of methane may occur from leaking natural gas piping components (process fugitives) associated with the proposed Project. The methane emissions from process fugitives have been conservatively estimated to be 141.2 tons per year (see Table 3-2) as $CO_2e$. This is a negligible (0.010%) contribution to the total GHG emissions from the project. However, for completeness, they are addressed in this BACT analysis.

#### 5.2.2.1 Identification of GHG Control Options

The only identified control technology for process fugitive emissions of $CO_2e$ is a leak detection and repair (LDAR) program. LDAR programs vary in stringency/degree of control as needed for control of VOC emissions; however due to the negligible amount of GHG emissions from fugitives, LDAR programs would not be considered for control of GHG emissions alone.

Table 5-4
Proposed Greenhouse Gas BACT Limits for SH8 (Simple Cycle Output Basis)

| Form of Limit | Limit | Averaging Period | Basis |
|---|---|---|---|
| Output-Based GHG Limit | 0.81 tons $CO_2e$/MWh [1] | 30-day rolling average | Simple cycle combustion turbine only gross output basis at full load |
| Heat Rate Limit | 13,872 Btu/kWh (HHV) [2] | 30-day rolling average | Simple cycle combustion turbine only gross output basis at full load |
| Annual GHG Emission Cap | 1,461,896 tons $CO_2e$/year | 365-day rolling average | Includes all stack emissions from combustion turbine, duct burner, start-ups, shutdowns, malfunctions and effects of different operating conditions including evaporative inlet air cooling |

1. Simple cycle (combustion turbine only) output based GHG limit is equivalent to 0.458 ton $CO_2e$/MWh (or 916 lb/MWh) for the combined cycle unit at full load at 68 degrees F
2. Simple cycle (combustion turbine only) heat rate limit is equivalent to 7,833 BTU/kWh (HHV) gross heat rate for the combined cycle unit at full load at 68 degrees F

#### *5.2.2.2 Elimination of Technically Infeasible Alternatives*

LDAR is considered technically feasible for the proposed Project.

#### *5.2.2.3 Ranking of Remaining Technologies Based on Effectiveness*

The use of a LDAR program with a portable gas analyzer meeting the requirements of 40 CFR 60, Appendix A, Method 21, can be effective for identifying leaking methane. Quarterly instrument monitoring with a leak definition of 10,000 part per million by volume (ppmv) (TCEQ 28M LDAR Program) is generally assigned a control efficiency of 75% for valves, relief valves, sampling connections, and compressors and 30% for flanges.[21] Quarterly instrument monitoring with a leak definition of 500 ppmv (TCEQ 28VHP LDAR Program) is generally assigned a control efficiency of 97% for valves, relief valves, and sampling connections, 85% for compressors, and 30% for flanges.[22] The EPA has allowed the use of an optical gas imaging instrument as an alternative work practice for a Method 21 portable analyzer to monitor equipment for leaks in 40 CFR 60.18(g). For components containing inorganic or odorous compounds, periodic audio/visual/olfactory (AVO) walk-through inspections provide predicted control efficiencies of 97% control for valves, flanges, relief valves, and sampling connections, and 95% for compressors.[23]

#### *5.2.2.4 Evaluation of Control Technologies*

A cost effectiveness analysis for a basic LDAR program to control process fugitive $CH_4$ emissions is presented in Appendix C, Table 3. The results of this analysis show that the least stringent LDAR program (TCEQ's 28M program) would cost approximately $260 per ton of $CO_2e$ removed, which is not considered to be cost effective for GHG control.

#### *5.2.2.5 Determination of BACT for Natural Gas Fugitives*

Due to the negligible amount of GHG emissions from process fugitives, the only available control, implementation of an LDAR program, is clearly not cost effective and would result in no significant reduction of overall project GHG emissions regardless of cost. Based on these considerations, BACT is determined to be normal plant maintenance practices as needed for safety and reliability purposes.

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[21] Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, TCEQ, Oct. 2000

[22] Id

[23] Id

### 5.2.3 BACT Analysis for $SF_6$ Insulated Electrical Equipment

#### *5.2.3.1 Identification of GHG Control Options*

State-of-the-art enclosed-pressure $SF_6$ technology with leak detection is the primary technology used to limit fugitive emissions. In comparison to older $SF_6$ circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for $SF_6$ emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the $SF_6$ (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the $SF_6$ has escaped, so that it can be addressed proactively to prevent further release of the gas.

A second alternative considered in this analysis is to substitute another, non-GHG substance for $SF_6$ as the dielectric material in the breakers. Potential alternatives to $SF_6$ were addressed in the National Institute of Standards and Technology (NTIS) Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure $SF_6$*.[24]

#### *5.2.3.2 Elimination of Technically Infeasible Alternatives*

According to the NTIS Technical Note 1425, $SF_6$ is a superior dielectric gas for nearly all high voltage applications.[25] It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of $SF_6$-insulated equipment. The report concluded that although "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture… it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Therefore there are currently no technically feasible options besides use of $SF_6$.

#### *5.2.3.3 Ranking of Remaining Technologies Based on Effectiveness*

The use of state-of-the-art $SF_6$ technology with leak detection to limit fugitive emissions is the highest ranked control technology that is technically feasible for this application.

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[24] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF6*, NIST Technical Note 1425, Nov.1997.
[25] Id at 28-29

#### 5.2.3.4 Evaluation of Control Technologies

Energy, environmental, or economic impacts were not addressed in this analysis because the use of alternative, non-greenhouse-gas substances to $SF_6$ as the dielectric material in the breakers is not technically feasible. A cost-effectiveness evaluation was not preformed given there is only one feasible option.

#### 5.2.3.5 Determination of BACT for GHG for $SF_6$ Insulated Electrical Equipment

The City of Austin proposes to use circuit breakers with totally enclosed insulation systems equipped with a low pressure alarm and low pressure lockout. The lockout will prevent operation of the breaker if insufficient $SF_6$ remains in the system.

# Appendix A
# TCEQ Applicable Forms

**Texas Commission on Environmental Quality**
**Form PI-1 General Application for**
**Air Preconstruction Permit and Amendment**

Important Note: The agency requires that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued and no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

| **I. Applicant Information** | | |
|---|---|---|
| A. Company or Other Legal Name: City of Austin dba Austin Energy | | |
| Texas Secretary of State Charter/Registration Number (if applicable): | | |
| B. Company Official Contact Name: Mr. Ravi Joseph | | |
| Title: Consulting Engineer | | |
| Mailing Address: 721 Barton Springs Road | | |
| City: Austin | State: Texas | ZIP Code: 78704 |
| Telephone No.: 512-322-6284 | Fax No.: 512-322-6280 | E-mail Address: ravi.joseph@austinenergy.com |
| C. Technical Contact Name: Mr. Ravi Joseph | | |
| Title: Consulting Engineer | | |
| Company Name: Austin Energy | | |
| Mailing Address: 721 Barton Springs Road | | |
| City: Austin | State: Texas | ZIP Code: 78704 |
| Telephone No.: 512-322-6284 | Fax No.: 512-322-6280 | E-mail Address: ravi.joseph@austinenergy.com |
| D. Site Name: Sand Hill Energy Center | | |
| E. Area Name/Type of Facility: Electric Generation Facility | | ☐ Permanent ☐ Portable |
| F. Principal Company Product or Business: Electric Power Production, Transmission and Distribution | | |
| Principal Standard Industrial Classification Code (SIC): 4911 | | |
| Principal North American Industry Classification System (NAICS): | | |
| G. Projected Start of Construction Date: 2nd Quarter of 2015 | | |
| Projected Start of Operation Date: 2nd Quarter of 2017 | | |
| H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.): | | |
| Street Address: 1102 Fallwell Lane | | |
| City/Town: Del Valle | County: Travis | ZIP Code: 78617 |
| Latitude (nearest second): 30° 12' 28" | Longitude (nearest second): 97° 36' 53" | |

# Texas Commission on Environmental Quality
# Form PI-1 General Application for Air Preconstruction Permit and Amendment

TCEQ

| | | |
|---|---|---|
| **I.** | **Applicant Information (continued)** | |
| I. | Account Identification Number (leave blank if new site or facility): | |
| J. | Core Data Form. | |
| Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L). | | ☐ YES ☐ NO |
| K. | Customer Reference Number (CN): | |
| L. | Regulated Entity Number (RN): | |
| **II.** | **General Information** | |
| A. | Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page. | ☐ YES ☐ NO |
| B. | Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above. | ☐ YES ☐ NO |
| C. | Number of New Jobs: | |
| D. | Provide the name of the State Senator and State Representative and district numbers for this facility site: | |
| State Senator: | | District No.: |
| State Representative: | | District No.: |
| **III.** | **Type of Permit Action Requested** | |
| A. | Mark the appropriate box indicating what type of action is requested. | |
| ☐ Initial ☐ Amendment ☐ Revision (30 TAC 116.116(e) ☐Change of Location ☐ Relocation | | |
| B. | Permit Number (if existing): | |
| C. | Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* | |
| ☐ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit | | |
| ☐ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source | | |
| ☐ Other: | | |
| D. | Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c). | ☐ YES ☐ NO |

# Texas Commission on Environmental Quality
# Form PI-1 General Application for
# Air Preconstruction Permit and Amendment

| **III.** | **Type of Permit Action Requested *(continued)*** | | |
|---|---|---|---|
| E. | Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.0 | | ☐ YES ☐ NO |
| 1. | Current Location of Facility (If no street address, provide clear driving directions to the site in writing.): | | |
| Street Address: | | | |
| | | | |
| City: | County: | ZIP Code: | |
| 2. | Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.): | | |
| Street Address: | | | |
| | | | |
| City: | County: | ZIP Code: | |
| 3. | Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO", attach detailed information. | | ☐ YES ☐ NO |
| 4. | Is the site where the facility is moving considered a major source of criteria pollutants or HAPs? | | ☐ YES ☐ NO |
| F. | Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown. | | |
| List: | | | |
| | | | |
| G. | Are you permitting planned maintenance, startup, and shutdown emissions? If Yes, attach information on any changes to emissions under this application as specified in VII and VIII. | | ☐ YES ☐ NO |
| H. | Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) Is this facility located at a site required to obtain a federal operating permit? If Yes, list all associated permit number(s), attach pages as needed). | | ☐ YES ☐ NO ☐ To be determined |
| Associated Permit No (s.): | | | |
| | | | |
| 1. | Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved. | | |
| ☐ FOP Significant Revision | ☐ FOP Minor | ☐ Application for an FOP Revision | |
| ☐ Operational Flexibility/Off-Permit Notification | | ☐ Streamlined Revision for GOP | |
| ☐ To be Determined | | ☐ None | |

| | | |
|---|---|---|
| **III.** | **Type of Permit Action Requested *(continued)*** | |
| H. | Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)* | |
| 2. | Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)*** | |
| ☐ GOP Issued | ☐ GOP application/revision application submitted or under APD review | |
| ☐ SOP Issued | ☐ SOP application/revision application submitted or under APD review | |
| **IV.** | **Public Notice Applicability** | |
| A. | Is this a new permit application or a change of location application? | ☐ YES ☐ NO |
| B. | Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2. | ☐ YES ☐ NO |
| C. | Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit? | ☐ YES ☐ NO |
| D. | Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area? | ☐ YES ☐ NO |
| If Yes, list the affected state(s) and/or Class I Area(s). | | |
| List: | | |
| E. | Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3. | |
| 1. | Is there any change in character of emissions in this application? | ☐ YES ☐ NO |
| 2. | Is there a new air contaminant in this application? | ☐ YES ☐ NO |
| 3. | Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)? | ☐ YES ☐ NO |
| F. | List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):*** | |
| Volatile Organic Compounds (VOC): | | |
| Sulfur Dioxide (SO2): | | |
| Carbon Monoxide (CO): | | |
| Nitrogen Oxides (NOx): | | |
| Particulate Matter (PM): | | |
| PM 10 microns or less (PM10): | | |
| PM 2.5 microns or less (PM2.5): | | |
| Lead (Pb): | | |
| Hazardous Air Pollutants (HAPs): | | |
| Other speciated air contaminants not listed above: | | |

| | | |
|---|---|---|
| **V. Public Notice Information *(complete if applicable)*** | | |
| A. Public Notice Contact Name: | | |
| Title: | | |
| Mailing Address: | | |
| City: | State: | ZIP Code: |
| B. Name of the Public Place: | | |
| Physical Address *(No P.O. Boxes)*: | | |
| City: | County: | ZIP Code: |
| The public place has granted authorization to place the application for public viewing and copying. | | ☐ YES ☐ NO |
| The public place has internet access available for the public. | | ☐ YES ☐ NO |
| C. Concrete Batch Plants, PSD, and Nonattainment Permits | | |
| 1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site. | | |
| The Honorable: | | |
| Mailing Address: | | |
| City: | State: | ZIP Code: |
| 2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)*** | | ☐ YES ☐ NO |
| Presiding Officers Name(s): | | |
| Title: | | |
| Mailing Address: | | |
| City: | State: | ZIP Code: |
| 3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. | | |
| Chief Executive: | | |
| Mailing Address: | | |
| City: | State: | ZIP Code: |
| Name of the Indian Governing Body: | | |
| Mailing Address: | | |
| City: | State: | ZIP Code: |

| | | |
|---|---|---|
| **V.** | **Public Notice Information *(complete if applicable) (continued)*** | |
| C. | Concrete Batch Plants, PSD, and Nonattainment Permits | |
| 3. | Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. *(continued)* | |
| Name of the Federal Land Manager(s): | | |
| D. | Bilingual Notice | |
| Is a bilingual program required by the Texas Education Code in the School District? | | ☐ YES ☐ NO |
| Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district? | | ☐ YES ☐ NO |
| If Yes, list which languages are required by the bilingual program? | | |
| **VI.** | **Small Business Classification *(Required)*** | |
| A. | Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts? | ☐ YES ☐ NO |
| B. | Is the site a major stationary source for federal air quality permitting? | ☐ YES ☐ NO |
| C. | Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy? | ☐ YES ☐ NO |
| D. | Are the site emissions of all regulated air pollutants combined less than 75 tpy? | ☐ YES ☐ NO |
| **VII.** | **Technical Information** | |
| A. | The following information must be submitted with your Form PI-1<br>***(this is just a checklist to make sure you have included everything)*** | |
| 1. | ☐ Current Area Map | |
| 2. | ☐ Plot Plan | |
| 3. | ☐ Existing Authorizations | |
| 4. | ☐ Process Flow Diagram | |
| 5. | ☐ Process Description | |
| 6. | ☐ Maximum Emissions Data and Calculations | |
| 7. | ☐ Air Permit Application Tables | |
| a. | ☐ Table 1(a) (Form 10153) entitled, Emission Point Summary | |
| b. | ☐ Table 2 (Form 10155) entitled, Material Balance | |
| c. | ☐ Other equipment, process or control device tables | |
| B. | Are any schools located within 3,000 feet of this facility? | ☐ YES ☐ NO |

| | | | | |
|---|---|---|---|---|
| **VII.** | **Technical Information** | | | |
| C. | Maximum Operating Schedule: | | | |
| Hour(s): | Day(s): | Week(s): | Year(s): | |
| Seasonal Operation? If Yes, please describe in the space provide below. | | | | ☐ YES ☐ NO |
| | | | | |
| D. | Have the planned MSS emissions been previously submitted as part of an emissions inventory? | | | ☐ YES ☐ NO |
| Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed. | | | | |
| | | | | |
| | | | | |
| E. | Does this application involve any air contaminants for which a disaster review is required? | | | ☐ YES ☐ NO |
| F. | Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)? | | | ☐ YES ☐ NO |
| **VIII.** | **State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.* | | | |
| A. | Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ? | | | ☐ YES ☐ NO |
| B. | Will emissions of significant air contaminants from the facility be measured? | | | ☐ YES ☐ NO |
| C. | Is the Best Available Control Technology (BACT) demonstration attached? | | | ☐ YES ☐ NO |
| D. | Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods? | | | ☐ YES ☐ NO |
| **IX.** | **Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.* | | | |
| A. | Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application? | | | ☐ YES ☐ NO |
| B. | Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application? | | | ☐ YES ☐ NO |

| | | |
|---|---|---|
| **IX.** | **Federal Regulatory Requirements**<br>**Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.* | |
| C. | Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application? | ☐ YES ☐ NO |
| D. | Do nonattainment permitting requirements apply to this application? | ☐ YES ☐ NO |
| E. | Do prevention of significant deterioration permitting requirements apply to this application? | ☐ YES ☐ NO |
| F. | Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application? | ☐ YES ☐ NO |
| G. | Is a Plant-wide Applicability Limit permit being requested? | ☐ YES ☐ NO |
| **X.** | **Professional Engineer (P.E.) Seal** | |
| Is the estimated capital cost of the project greater than $2 million dollars? | | ☐ YES ☐ NO |
| If Yes, submit the application under the seal of a Texas licensed P.E. | | |
| **XI.** | **Permit Fee Information** | |
| Check, Money Order, Transaction Number ,ePay Voucher Number: | | Fee Amount: $ |
| Paid online? | | ☐ YES ☐ NO |
| Company name on check: | | |
| Is a copy of the check or money order attached to the original submittal of this application? | | ☐ YES ☐ NO ☐ N/A |
| Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached? | | ☐ YES ☐ NO ☐ N/A |

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

| | |
|---|---|
| **XII. Delinquent Fees and Penalties** | |
| This form will not be processed until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html. | |
| **XIII. Signature** | |
| The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties. | |
| Name: | |
| Signature:______________________________ *Original Signature Required* | |
| Date: | |

PRINT FORM RESET FORM

# TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

## Table 1(a) Emission Point Summary

| **Date: August 2013** | **Permit No.: 48106 and PSD-TX1012-M1** | **Regulated Entity No.: RN100215052** |
|---|---|---|
| **Area Name: City of Austin Sand Hill Energy Center (SHEC)** | | **Customer Reference No.: CN600135198** |

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

| **AIR CONTAMINANT DATA** | | | | | |
|---|---|---|---|---|---|
| **1. Emission Point** | | | **2. Component or Air Contaminant Name** | **3. Air Contaminant Emission Rate** | |
| **(A) EPN** | **(B) FIN** | **(C) Name** | | **(A) Pound Per Hour** | **(B) TPY** |
| SH8 | SH8 | GE 7FA.04 w/HRSG Combined | $CO_2e$ | 333,766 lb/hr | 1,461,896 TPY |
| CC MS FUG | CC MS FUG | Combined Cycle Natural Gas Meter | $CO_2e$ | 32.2 lb/hr | 141 TPY |
| SF6 FUG | SF6 FUG | SF6 Fugitives | $CO_2e$ | 0.77 | 3 tpy |
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EPN = Emission Point Number
FIN = Facility Identification Number

TCEQ

# TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

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|---|---|---|
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| **AIR CONTAMINANT DATA** | | | | | | **EMISSION POINT DISCHARGE PARAMETERS** | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **1. Emission Point** | | | **4. UTM Coordinates of Emission Point** | | | **Source** | | | | | | | |
| | | | | | | **5. Building Height (Ft.)** | **6. Height Above Ground (Ft.)** | **7. Stack Exit Data** | | | **8. Fugitives** | | |
| **(A) EPN** | **(B) FIN** | **(C) NAME** | **Zone** | **East (Meters)** | **North (Meters)** | | | **(A) Diameter (Ft.)** | **(B) Velocity (FPS)** | **(C) Temperature (°F)** | **(A) Length (Ft.)** | **(B) Width (Ft.)** | **(C) Axis Degrees** |
| SH8 | SH8 | GE 7FA.04 w/HRSG | 14 | 633,590 | 3,342,923 | --- | 157.5 | 18.05 | 40.15 | 200 | --- | --- | --- |
| CC MS FUG | CC MS FUG | Combined Cycle Natural Gas Meter | 14 | 633,514 | 3,342,925 | --- | 3.0 | --- | --- | --- | 30 | 20 | 40 |
| SF6 FUG | SF6 FUG | SF6 Fugitives | 14 | 633,549 | 3,342,875 | --- | 3.0 | | | | 10 | 10 | 100 |
| | | | | | | | | | | | | | |
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EPN = Emission Point Number
FIN = Facility Identification Number

# Appendix B
# Emissions Calculations and Documentation

## Appendix B, Table 1
## Estimated Performance and Emissions for GE 7FA.04 Combustion Turbine in Simple Cycle and Combined Cycle Mode

| | MODE NUMBER | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| oad Condition | % CTG Base Load | **BASE** | **BASE** | **75%** | **50%** | **BASE** | **BASE** | **BASE** | **75%** | **53%** | **BASE** | **BASE** | **BASE** | **75%** | **69%** |
| mbient Temperature | deg F | **0** | **0** | **0** | **0** | **68** | **68** | **68** | **68** | **68** | **112** | **112** | **112** | **112** | **112** |
| vap. Cooler Status | | Off | Off | Off | Off | **On** | **On** | Off | Off | Off | **On** | **On** | Off | Off | Off |
| vap. Cooler Effectiveness | % | 0 | 0 | 0 | 0 | 85 | 85 | 0 | 0 | 0 | 85 | 85 | 0 | 0 | 0 |
| uct Burner Status | | **On** | Off | Off | Off | **On** | Off | Off | Off | Off | **On** | Off | Off | Off | Off |
| mbient Relative Humidity | % | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 | 60 |
| let Loss | in H2O | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| xhaust Pressure Loss | in H2O | 16.1 | 16.1 | 10.7 | 7.3 | 14.4 | 14.4 | 14 | 9.5 | 7 | 11.5 | 11.5 | 10.7 | 8 | 7.4 |
| uel Type | | Cust Gas | Cust Gas | Cust Gas | Cust Gas | Cust Gas | Cust Gas | Cust Gas | Cust Gas | Cust Gas | Cust Gas | Cust Gas | Cust Gas | Cust Gas | Cust Gas |
| uel LHV | BTU/lb | 20,460 | 20,460 | 20,460 | 20,460 | 20,460 | 20,460 | 20,460 | 20,460 | 20,460 | 20,460 | 20,460 | 20,460 | 20,460 | 20,460 |
| uel Temperature | deg F | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 |
| TG Output (Simple Cycle) | kW | 196,178 | 196,178 | 147,133 | 98,089 | 179,025 | 179,025 | 173,910 | 130,433 | 92,172 | 152,206 | 152,206 | 142,802 | 107,101 | 98,533 |
| TG Output (estimated)* | kW | 168,683 | 102,365 | 86,067 | 74,672 | 162,271 | **95,953** | 94,620 | 80,141 | 71,053 | 153,844 | 87,526 | 85,269 | 75,042 | 72,240 |
| C (CTG + STG) Combined Cycle Output | kW | 364,861 | 298,543 | 233,200 | 172,761 | 341,296 | 274,978 | 268,530 | 210,574 | 163,225 | 306,050 | 239,732 | 228,071 | 182,143 | 170,773 |
| TG Simple Cycle Heat Rate (LHV) | BTU/kWh, LHV | 8,792 | 8,792 | 9,440 | 11,252 | 8,991 | 8,991 | 9,041 | 9,766 | 11,379 | 9,433 | 9,433 | 9,600 | 10,670 | 11,007 |
| TG Simple Cycle Heat Rate (HHV) | BTU/kWh, HHV | 9,744 | 9,744 | 10,462 | 12,470 | 9,964 | 9,964 | 10,020 | 10,823 | 12,611 | 10,454 | 10,454 | 10,639 | 11,825 | 12,199 |
| TG Simple Cycle Thermal Efficiency | % | 35.0% | 35.0% | 32.6% | 27.4% | 34.3% | 34.3% | 34.1% | 31.5% | 27.1% | 32.6% | 32.6% | 32.1% | 28.9% | 28.0% |
| TG Simple Cycle Heat Rate, LHV (+ margin**) | BTU/kWh, LHV | 9,671 | 9,671 | 10,384 | 12,377 | 9,890 | 9,890 | 9,945 | 10,743 | 12,517 | 10,376 | 10,376 | 10,560 | 11,737 | 12,108 |
| TG Simple Cycle Heat Rate, HHV (+ margin**) | BTU/kWh, HHV | 10,718 | 10,718 | 11,508 | 13,717 | 10,961 | 10,961 | 11,022 | 11,906 | 13,872 | 11,500 | 11,500 | 11,703 | 13,008 | 13,419 |
| ombined Cycle (CTG + STG) Heat Rate (LHV) | BTU/kWh | 6,410 | 5,778 | 5,956 | 6,389 | 6,515 | 5,854 | 5,855 | 6,049 | 6,426 | 6,697 | 5,989 | 6,011 | 6,274 | 6,351 |
| ombined Cycle (CTG + STG) Heat Rate (HHV) | BTU/kWh, HHV | 7,104 | 6,403 | 6,601 | 7,080 | 7,221 | 6,488 | 6,489 | 6,704 | 7,121 | 7,422 | 6,637 | 6,662 | 6,953 | 7,038 |
| ombined Cycle (CTG + STG) Thermal Efficiency | % | 48.0% | 53.3% | 51.7% | 48.2% | 47.3% | 52.6% | 52.6% | 50.9% | 47.9% | 46.0% | 51.4% | 51.2% | 49.1% | 48.5% |
| ombined Cycle (CTG + STG) Heat Rate (+ margin**) | BTU/kWh, LHV | 7,051 | 6,355 | 6,552 | 7,027 | 7,167 | 6,439 | 6,440 | 6,654 | 7,068 | 7,367 | 6,588 | 6,612 | 6,901 | 6,986 |
| ombined Cycle (CTG + STG) Heat Rate (+ margin**) | BTU/kWh, HHV | 7,815 | 7,044 | 7,261 | 7,788 | 7,943 | 7,136 | 7,138 | 7,375 | 7,833 | 8,165 | 7,301 | 7,328 | 7,648 | 7,742 |
| TG Heat Cons. (LHV) | MMBTU/hr | 1,724.9 | 1,724.9 | 1,389.0 | 1,103.7 | 1,609.7 | 1,609.7 | 1,572.2 | 1,273.8 | 1,048.8 | 1,435.7 | 1,435.7 | 1,371.0 | 1,142.7 | 1,084.5 |
| TG Heat Consumption (HHV) | MMBTU/hr | 1,911.6 | 1,911.6 | 1,539.4 | 1,223.2 | 1,784.0 | 1,784.0 | 1,742.4 | 1,411.7 | 1,162.4 | 1,591.1 | 1,591.1 | 1,519.4 | 1,266.4 | 1,201.9 |
| G Exhaust Flow | x10^3 lb/hr | 3,733 | 3,733 | 3,019 | 2,466 | 3,493 | 3,493 | 3,435 | 2,804 | 2,389 | 3,086 | 3,086 | 2,979 | 2,557 | 2,464 |
| G Exhaust Temperature | deg F | 1,076 | 1,076 | 1,116 | 1,182 | 1,130 | 1,130 | 1,134 | 1,172 | 1,215 | 1,177 | 1,177 | 1,188 | 1,215 | 1,215 |
| xhaust Molecular Weight | lb/lbmol | 28.48 | 28.48 | 28.49 | 28.5 | 28.32 | 28.32 | 28.35 | 28.35 | 28.37 | 27.87 | 27.87 | 27.91 | 27.93 | 27.93 |

## Appendix B, Table 1
## Estimated Performance and Emissions for GE 7FA.04 Combustion Turbine in Simple Cycle and Combined Cycle Mode

OMBUSTION TURBINE EMISSIONS

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ox | ppmvd @ 15% O2 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| Ox AS NO2 | lb/hr | 62 | 62 | 50 | 40 | 58 | 58 | 57 | 46 | 38 | 52 | 52 | 50 | 41 | 39 |
| D | ppmvd | 9 | 9 | 9 | 11 | 9 | 9 | 9 | 9 | 11 | 9 | 9 | 9 | 9 | 10 |
| D | lb/hr | 31 | 31 | 25 | 24 | 28 | 28 | 28 | 23 | 25 | 24 | 24 | 23 | 20 | 23 |
| HC | ppmvw | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 |
| HC | lb/hr | 15 | 15 | 12 | 10 | 14 | 14 | 14 | 11 | 9 | 12 | 12 | 12 | 10 | 10 |
| OC | ppmvw | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 |
| OC | lb/hr | 3.0 | 3.0 | 2.4 | 2.0 | 2.8 | 2.8 | 2.8 | 2.2 | 1.8 | 2.4 | 2.4 | 2.4 | 2.0 | 2.0 |
| M/PM-10/PM-2.5 (filterable) | lb/hr | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 |
| M/PM-10/PM-2.5 (f+c) | lb/hr | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| O2 | lb/MMBTU, HHV | 0.000642 | 0.000642 | 0.000642 | 0.000642 | 0.000642 | 0.000642 | 0.000642 | 0.000642 | 0.000642 | 0.000642 | 0.000642 | 0.000642 | 0.000642 | 0.000642 |
| O2 | lb/hr | 1.23 | 1.23 | 0.99 | 0.79 | 1.15 | 1.15 | 1.12 | 0.91 | 0.75 | 1.02 | 1.02 | 0.98 | 0.81 | 0.77 |
| O2 (per 40 CFR 98 Table C-1 EFs) | lb/MMBTU, HHV | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 |
| O2 (per 40 CFR 98 Table C-1 EFs) | lb/hr | 223,447 | 223,447 | 179,934 | 142,976 | 208,524 | 208,524 | 203,666 | 165,011 | 135,864 | 185,984 | 185,984 | 177,602 | 148,028 | 140,488 |
| 2O (per 40 CFR 98 Table C-2 EFs) | lb/MMBTU, HHV | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 |
| 2O (per 40 CFR 98 Table C-2 EFs) | lb/hr | 0.42 | 0.42 | 0.34 | 0.27 | 0.39 | 0.39 | 0.38 | 0.31 | 0.26 | 0.35 | 0.35 | 0.33 | 0.28 | 0.26 |
| H4 (per 40 CFR 98 Table C-2 EFs) | lb/MMBTU, HHV | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 |
| H4 (per 40 CFR 98 Table C-2 EFs) | lb/hr | 4.21 | 4.21 | 3.39 | 2.70 | 3.93 | 3.93 | 3.84 | 3.11 | 2.56 | 3.51 | 3.51 | 3.35 | 2.79 | 2.65 |
| HG, CO2e (per 40 CFR 98 EFs) | lb/hr | 223,666 | 223,666 | 180,110 | 143,116 | 208,728 | 208,728 | 203,866 | 165,173 | 135,997 | 186,166 | 186,166 | 177,776 | 148,173 | 140,626 |
| HG, CO2e (per 40 CFR 98 EFs) | lb/MMBTU, HHV | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 |

OMBUSTION TURBINE EXHAUST ANALYSIS % VOL.

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| rgon | % by volume | 0.90 | 0.90 | 0.89 | 0.90 | 0.89 | 0.89 | 0.88 | 0.88 | 0.89 | 0.85 | 0.85 | 0.84 | 0.84 | 0.84 |
| itrogen | % by volume | 75.08 | 75.08 | 75.09 | 75.17 | 73.91 | 73.91 | 74.12 | 74.14 | 74.24 | 70.67 | 70.67 | 71.00 | 71.08 | 71.12 |
| xygen | % by volume | 12.50 | 12.50 | 12.54 | 12.76 | 12.25 | 12.25 | 12.35 | 12.42 | 12.69 | 11.43 | 11.43 | 11.59 | 11.83 | 11.94 |
| arbon Dioxide | % by volume | 3.91 | 3.91 | 3.90 | 3.79 | 3.88 | 3.88 | 3.86 | 3.83 | 3.70 | 3.85 | 3.85 | 3.82 | 3.71 | 3.66 |
| 'ater | % by volume | 7.61 | 7.61 | 7.58 | 7.38 | 9.08 | 9.08 | 8.79 | 8.73 | 8.49 | 13.20 | 13.20 | 12.75 | 12.54 | 12.44 |
| OTAL | | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |

## Appendix B, Table 1
## Estimated Performance and Emissions for GE 7FA.04 Combustion Turbine in Simple Cycle and Combined Cycle Mode

UCT BURNER EMISSIONS

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| uct Burner Firing Rate* | MMBTU/hr, LHV | 614.0 | | | | 614.0 | | | | | 614.0 | | | | |
| uct Burner Firing Rate* | MMBTU/hr, HHV | 681.5 | | | | 681.5 | | | | | 681.5 | | | | |
| Ox | lb/MMBTU, HHV | 0.10 | | | | 0.10 | | | | | 0.10 | | | | |
| Ox | lb/hr | 68.15 | | | | 68.15 | | | | | 68.15 | | | | |
| D | lb/MMBTU, HHV | 0.10 | | | | 0.10 | | | | | 0.10 | | | | |
| D | lb/hr | 68.15 | | | | 68.15 | | | | | 68.15 | | | | |
| OC (per EPA AP-42 Table 1.4-2) | lb/MMBTU, HHV | 0.0054 | | | | 0.0054 | | | | | 0.0054 | | | | |
| OC | lb/hr | 3.67 | | | | 3.67 | | | | | 3.67 | | | | |
| M/PM-10/PM-2.5 (F+C) (per EPA AP-42 Table 1.4-2) | lb/MMBTU, HHV | 0.0074 | | | | 0.0074 | | | | | 0.0074 | | | | |
| M/PM-10/PM-2.5 (F+C) | lb/hr | 5.07 | | | | 5.07 | | | | | 5.07 | | | | |
| D2 | lb/MMBTU, HHV | 0.00064 | | | | 0.00064 | | | | | 0.00064 | | | | |
| D2 | lb/hr | 0.44 | | | | 0.44 | | | | | 0.44 | | | | |
| D2 (per 40 CFR 98 Table C-1 EF) | lb/MMBTU, HHV | 116.9 | | | | 116.9 | | | | | 116.9 | | | | |
| D2 (per 40 CFR 98 Table C-1 EF) | lb/hr | 79,663 | | | | 79,663 | | | | | 79,663 | | | | |
| 2O (per 40 CFR 98 Table C-1 EF) | lb/MMBTU, HHV | 0.0002 | | | | 0.0002 | | | | | 0.0002 | | | | |
| 2O (per 40 CFR 98 Table C-1 EF) | lb/hr | 0.15 | | | | 0.15 | | | | | 0.15 | | | | |
| H4 (per 40 CFR 98 Table C-1 EF) | lb/MMBTU, HHV | 0.0022 | | | | 0.0022 | | | | | 0.0022 | | | | |
| H4 (per 40 CFR 98 Table C-1 EF) | lb/hr | 1.50 | | | | 1.50 | | | | | 1.50 | | | | |
| HG, CO2e (per 40 CFR 98 EF & GWP) | lb/MMBTU, HHV | 117.0 | | | | 117.0 | | | | | 117.0 | | | | |
| HG, CO2e (per 40 CFR 98 EF & GWP) | lb/hr | 79,741 | | | | 79,741 | | | | | 79,741 | | | | |

RSG EXHAUST COMPOSITION (VOLUME %)

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| rgon | % by volume | 0.89% | 0.90% | 0.89% | 0.90% | 0.88% | 0.89% | 0.88% | 0.88% | 0.89% | 0.84% | 0.85% | 0.84% | 0.84% | 0.84% |
| itrogen | % by volume | 74.09% | 75.08% | 75.09% | 75.17% | 72.87% | 73.90% | 74.12% | 74.14% | 74.23% | 69.57% | 70.67% | 71.00% | 71.08% | 71.12% |
| xygen | % by volume | 9.65% | 12.50% | 12.54% | 12.76% | 9.22% | 12.25% | 12.35% | 12.42% | 12.69% | 8.08% | 11.43% | 11.59% | 11.83% | 11.94% |
| arbon Dioxide | % by volume | 5.22% | 3.91% | 3.90% | 3.79% | 5.27% | 3.88% | 3.86% | 3.83% | 3.70% | 5.40% | 3.85% | 3.82% | 3.71% | 3.66% |
| ater | % by volume | 10.15% | 7.61% | 7.58% | 7.38% | 11.75% | 9.08% | 8.79% | 8.73% | 8.49% | 16.11% | 13.20% | 12.75% | 12.54% | 12.44% |
| OTAL | | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |

RSG FLUE GAS MOLECULAR WT

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ue Gas | lb/lb-mole | 28.33 | 28.49 | 28.49 | 28.50 | 28.16 | 28.33 | 28.35 | 28.36 | 28.37 | 27.69 | 27.87 | 27.92 | 27.93 | 27.94 |

RSG STACK EXHAUST PARAMETERS

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ack Height AGL | ft | 127.0 | 127.0 | 127.0 | 127.0 | 127.0 | 127.0 | 127.0 | 127.0 | 127.0 | 127.0 | 127.0 | 127.0 | 127.0 | 127.0 |
| ack Diameter | ft | 19.0 | 19.0 | 19.0 | 19.0 | 19.0 | 19.0 | 19.0 | 19.0 | 19.0 | 19.0 | 19.0 | 19.0 | 19.0 | 19.0 |
| ack Exhaust Temperature | Degrees F | 200.0 | 200.0 | 200.0 | 200.0 | 200.0 | 200.0 | 200.0 | 200.0 | 200.0 | 200.0 | 200.0 | 200.0 | 200.0 | 200.0 |
| ack Exhaust Flow Rate | ACFM | 1,066,827 | 1,052,528 | 850,915 | 694,806 | 1,004,821 | 990,522 | 972,947 | 794,219 | 676,263 | 903,448 | 889,149 | 857,090 | 735,149 | 708,411 |
| ack Exit Velocity | ft/s | 62.7 | 61.9 | 50.0 | 40.8 | 59.1 | 58.2 | 57.2 | 46.7 | 39.8 | 53.1 | 52.3 | 50.4 | 43.2 | 41.6 |

**Appendix B, Table 1**

**Estimated Performance and Emissions for GE 7FA.04 Combustion Turbine in Simple Cycle and Combined Cycle Mode**

NCONTROLLED & CONTROLLED EMISSIONS (TURBINE + DUCT BURNER)

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Ox Uncontrolled | lb/hr | 130.2 | 62.0 | 50.0 | 40.0 | 126.2 | 58.0 | 57.0 | 46.0 | 38.0 | 120.2 | 52.0 | 50.0 | 41.0 | 39.0 |
| Ox Uncontrolled | ppmvd@15%O2 | 13.6 | 9.7 | 9.7 | 8.3 | 12.7 | 8.1 | 8.1 | 8.1 | 8.2 | 12.0 | 7.7 | 7.8 | 7.7 | 7.8 |
| Ox Controlled | lb/hr | 19.2 | 12.7 | 10.4 | 9.6 | 19.9 | 14.4 | 14.0 | 11.3 | 9.3 | 20.1 | 13.5 | 12.8 | 10.6 | 10.1 |
| Ox Controlled | ppmvd@15%O2 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| ) Uncontrolled | lb/hr | 99.2 | 31.0 | 25.0 | 24.0 | 96.2 | 28.0 | 28.0 | 23.0 | 25.0 | 92.2 | 24.0 | 23.0 | 20.0 | 23.0 |
| ) Uncontrolled | ppmvd@15%O2 | 17.0 | 8.0 | 7.9 | 8.2 | 15.9 | 6.4 | 6.6 | 6.7 | 8.8 | 15.1 | 5.9 | 5.9 | 6.2 | 7.5 |
| ) Controlled | lb/hr | 11.7 | 7.8 | 6.3 | 5.8 | 12.1 | 8.8 | 8.5 | 6.9 | 5.7 | 12.2 | 8.2 | 7.8 | 6.5 | 6.1 |
| ) Controlled | ppmvd@15%O2 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| DC | lb/hr | 6.7 | 3.0 | 2.4 | 2.0 | 6.5 | 2.8 | 2.8 | 2.2 | 1.8 | 6.1 | 2.4 | 2.4 | 2.0 | 2.0 |
| DC | ppmvd@15%O2 | 2.0 | 1.4 | 1.3 | 1.2 | 1.9 | 1.1 | 1.1 | 1.1 | 1.1 | 1.7 | 1.0 | 1.1 | 1.1 | 1.1 |
| M/PM-10/PM-2.5 (F+C) | lb/hr | 17.1 | 12.0 | 12.0 | 12.0 | 17.1 | 12.0 | 12.0 | 12.0 | 12.0 | 17.1 | 12.0 | 12.0 | 12.0 | 12.0 |
| M/PM-10/PM-2.5 (F+C) | lb/MMBTU, HHV | 0.0066 | 0.0063 | 0.0078 | 0.0098 | 0.0069 | 0.0067 | 0.0069 | 0.0085 | 0.0103 | 0.0075 | 0.0075 | 0.0079 | 0.0095 | 0.0100 |
| M-10 incl. Ammonia Salts | lb/hr | 18.4 | 13.0 | 12.8 | 12.6 | 18.4 | 12.9 | 12.9 | 12.7 | 12.6 | 18.3 | 12.8 | 12.8 | 12.7 | 12.6 |
| M-10 incl. Ammonia Salts | lb/MMBTU, HHV | 0.0071 | 0.0068 | 0.0083 | 0.0103 | 0.0075 | 0.0073 | 0.0074 | 0.0090 | 0.0109 | 0.0080 | 0.0081 | 0.0084 | 0.0100 | 0.0105 |
| )2 | lb/hr | 1.67 | 1.23 | 0.99 | 0.79 | 1.58 | 1.15 | 1.12 | 0.91 | 0.75 | 1.46 | 1.02 | 0.98 | 0.81 | 0.77 |
| )2 | lb/MMBTU, HHV | 0.00064 | 0.00064 | 0.00064 | 0.00064 | 0.00064 | 0.00064 | 0.00064 | 0.00064 | 0.00064 | 0.00064 | 0.00064 | 0.00064 | 0.00064 | 0.00064 |
| 2SO4 | lb/hr | 1.02 | 0.75 | 0.61 | 0.48 | 0.97 | 0.70 | 0.69 | 0.56 | 0.46 | 0.89 | 0.63 | 0.60 | 0.50 | 0.47 |
| 2SO4 | lb/MMBTU, HHV | 0.00039 | 0.00039 | 0.00039 | 0.00039 | 0.00039 | 0.00039 | 0.00039 | 0.00039 | 0.00039 | 0.00039 | 0.00039 | 0.00039 | 0.00039 | 0.00039 |
| )2 | lb/hr | 303,110 | 223,447 | 179,934 | 142,976 | 288,187 | 208,524 | 203,666 | 165,011 | 135,864 | 265,647 | 185,984 | 177,602 | 148,028 | 140,488 |
| )2 | lb/MMBTU, HHV | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 | 116.9 |
| 2O | lb/hr | 0.6 | 0.4 | 0.3 | 0.3 | 0.5 | 0.4 | 0.4 | 0.3 | 0.3 | 0.5 | 0.4 | 0.3 | 0.3 | 0.3 |
| 2O | lb/MMBTU, HHV | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 |
| H4 | lb/hr | 5.7 | 4.2 | 3.4 | 2.7 | 5.4 | 3.9 | 3.8 | 3.1 | 2.6 | 5.0 | 3.5 | 3.3 | 2.8 | 2.6 |
| H4 | lb/MMBTU, HHV | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 | 0.0022 |
| HG, CO2e | lb/hr | 303,408 | 223,666 | 180,110 | 143,116 | 288,470 | 208,728 | 203,866 | 165,173 | 135,997 | 265,907 | 186,166 | 177,776 | 148,173 | 140,626 |
| HG, CO2e | lb/MMBTU, HHV | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 |
| HG, CO2e (Simple Cycle) | ton/MWh | 0.773 | 0.570 | 0.612 | 0.730 | 0.806 | 0.583 | 0.586 | 0.633 | 0.738 | 0.874 | 0.612 | 0.622 | 0.692 | 0.714 |
| HG, CO2e (Simple Cycle + margin**) | ton/MWh | 0.851 | 0.627 | 0.673 | 0.802 | 0.886 | 0.641 | 0.645 | 0.696 | 0.812 | 0.961 | 0.673 | 0.685 | 0.761 | 0.785 |
| HG, CO2e (Combined Cycle) | ton/MWh | 0.416 | 0.375 | 0.386 | 0.414 | 0.423 | 0.380 | 0.380 | 0.392 | 0.417 | 0.434 | 0.388 | 0.390 | 0.407 | 0.412 |
| HG, CO2e (Combined Cycle + margin**) | ton/MWh | 0.457 | 0.412 | 0.425 | 0.456 | 0.465 | 0.417 | 0.418 | 0.431 | 0.458 | 0.478 | 0.427 | 0.429 | 0.447 | 0.453 |
| H3 Slip | ppmvd @ 15% O2 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 | 7.0 |
| H3 Slip | lb/hr | 24.9 | 16.5 | 13.4 | 12.4 | 25.7 | 18.6 | 18.1 | 14.7 | 12.0 | 26.0 | 17.4 | 16.6 | 13.7 | 13.0 |

STG output (kW) estimated by scaling from design case (68 F, evap cooler on, unfired) based on ratio of exhaust energy + duct burner heat input to design case exhaust energy; actual STG output limited to 148 MW with only 1 CTG perating, but maximum duct burner firing rate used for all conditions as worst case for permitting

Margin added for measurement error, off-design conditions and degradation 10.0%

ombustion turbine performance and emissions data based on GE Energy gas turbine performance simulation runs at site specific conditions; supplemental data calculated as follows

rmulas / Example Calculations:

khaust mole flow rate = exhaust mass flow rate / flue gas molecular weight = lb/hr / lb/lb-mole = lb-mole/hr

ry exhaust mole flow rate = lb-mole/hr x (1- %H20/100)

ry mole flow rate at 15% O2 = dry lb-mole/hour x (20.9 - % O2 dry)/(20.9/15)

llutant lb/hr = lb-mole/hr, dry basis, at 15 % O2 x ppmvd @ 15% O2 dry /$10^6$ x molecular weight, lb/lb-mole

eat Rate (Btu/kWh) = Heat Input Rate (MMBtu/hr) x (10^6 BTU/MMBtu) / Generator Output (MW) / (MW/1000 kW)

**Appendix B, Table 2: Annual GHG Emission Calculations – New Combined Cycle Combustion Turbine**

| Source | Annual Fuel Use[1] (MMBtu/yr) | Pollutant | Emission Factor[2] (kg/MMBtu) | GHG Mass Emissions (tons/yr) | Global Warming Potential[3] | $CO_2$e (tons/yr) |
|---|---|---|---|---|---|---|
| Combustion turbine combined cycle unit | 22,716,339 | $CO_2$ | 53.02 | 1,327,623.8 | 1 | 1,327,624 |
| | | $CH_4$ | 1.00E-03 | 25.0 | 25 | 626 |
| | | $N_2O$ | 1.00E-04 | 2.5 | 298 | 746 |
| | | GHG | **Totals** | **1,327,651** | | **1,328,996** |
| | | CO2e | Margin added for measurement error = | | 10% | **1,461,896** |

[1] Annual heat input based on 8760 hours per year of operation of the combustion turbine at an average ambient temperature of 68°F with evaporative cooling on and a duct burner firing at 681.5 MMBtu/hr for 8760 hours per year.

[2] $CO_2$, $CH_4$ and $N_2O$ emission factors based on Tables C-1 and C-1 of 40 CFR 98.

[3] Global warming potential factors based on Table A-1 of 40 CFR 98.

<u>Example Calculations:</u>

Combustion Turbine Fuel = 8760 hr/yr x 1911.6 MMBtu/hr = 16,746,049 MMBtu/yr
Duct Burner Fuel = 8760 hr/yr x 681.5 MMBtu/hr = 5,970,290 MMBtu/yr
Total Fuel = 16,746,049 + 5,970,290 = 22,716,339 MMBtu/yr

Carbon Dioxide
22,716,339 MMBtu/hr x (53.02 kg CO2/MMBtu) x (2.2046 lb/kg) / (2000 lb/ton) x 1 CO2e/CO2 = 1,327,624 tons CO2e/yr

Methane
22,716,339 MMBtu/hr x (0.001 kg CH4/MMBtu) x (2.2046 lb/kg) / (2000 lb/ton) x 25 CO2e/CH4= 626 tons CO2e/yr

Nitrous Oxides
22,716,339 MMBtu/hr x (0.0001 kg N2O/MMBtu) x (2.2046 lb/kg) / (2000 lb/ton) x 298 CO2e/N2O = 746 tons CO2e/yr

**Appendix B, Table 3: Natural Gas Fugitive GHG Emission Calculations**

| Source | Component Type | Fluid State | Count | Emission Factor[1] (scf/hr/component) | $CO2^2$ (tons/yr) | $CH4^3$ (tons/yr) | Total (tons/yr) |
|---|---|---|---|---|---|---|---|
| Natural Gas Fugitives | Valves | Gas/Vapor | 194 | 0.121 | 0.093 | 4.02 | |
| | Flanges | | 161 | 0.017 | 0.011 | 0.47 | |
| | Relief Valve | | 35 | 0.193 | 0.027 | 1.16 | |
| GHG Mass Based Emissions | | | | | 0.130 | 5.64 | 5.77 |
| Global Warming Potential[4] | | | | | 1 | 25 | |
| $CO_2$e Emissions | | | | | 0.130 | 141.0 | **141.2** |

[1] Emission factors from Table W-1A of 40 CFR Part 98 Mandatory Greenhouse Gas Reporting

[2] $CO_2$ emissions based on vol % $CO_2$ in natural gas of 0.79%

[3] $CH_4$ emissions based on vol % $CH_4$ in natural gas of 94.14%

[4] Global warming potential based on Table A-1 of 40 CFR Part 98 Mandatory Greenhouse Gas Reporting

<u>Example Calculations</u>

CO2 Emissions from Valves

194 valves x (0.121 scf gas/hr-valve) x (0.0079 scf CO2/scf gas) / (385.5 scf/lb-mole) x (44 lb CO2/lb-mole) x (8760 hr/yr) / (2000 lb/ton) = 0.093 ton CO2 / year

CH4 Emissions from Valves

194 valves x (0.121 scf gas/hr-valve) x (0.9414 scf CH4/scf gas) / (385.5 scf/lb-mole) x (16 lb CH4/lb-mole) x (8760 hr/yr) / (2000 lb/ton) = 4.017 tons CH4 / year

# Appendix C
# BACT Analysis Calculations and Documentation

Appendix C, Table 1
Recent Permit Limits for Natural Gas-Fired Combined Cycle Combustion Turbines > 25 MW
Greenhouse Gas Emissions

| FACILITY | STATE | PERMIT STATUS | PERMIT DATE | STATUS OPER? | EQUIPMENT DETAILS | CONTROL TECHNOLOGY | OUTPUT BASIS LB/MWH | HEAT RATE BTU/KWH | INPUT BASIS LB/MMBTU | CO2e CAP TONS/YR | LIMIT BASIS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| RUSSELL CITY | CA | FINAL | 2/3/2010 | NO | NGCC | EFFICIENT CTGs NG | | 7,730 | | | VOLUNTARY |
| PACIFICORP | UT | FINAL | 5/4/2011 | NO | NGCC | EFFICIENT CTGs & HRSG | 950 | | | | BACT |
| ROBINSON POWER | PA | FINAL | 6/30/2011 | NO | NGCC 1 x GE 7EA + DB | EFFICIENT CTGs | | | | 620,000 | VOLUNTARY |
| PALMDALE | CA | FINAL | 10/18/2011 | NO | NGCC W/SOLAR | EFFICIENT CTGs & SOLAR | 774* | 7,319 | 117 | 1,913,000 | BACT |
| LCRA FERGUSON | TX | FINAL | 11/10/2011 | NO | NGCC | EFFICIENT CTGs | 918 | 7,720 | | | BACT |
| KENNECOTT | UT | FINAL | 11/22/2011 | NO | NGCC | EFFICIENT CTGs | | 7,642 | | | BACT |
| PIONEER VALLEY | MA | FINAL | 4/12/2012 | NO | NGCC MITSUBISHI 501G | EFFICIENT CTGs | 895 | | | | BACT |
| CPV VALLEY | NY | DRAFT | 7/11/2012 | NO | NGCC SIEMENS F | EFFICIENT CTGs | 925 | | | | BACT |
| WOODBRIDGE | NJ | FINAL | 8/24/2012 | NO | NGCC GE 7FA | EFFICIENT CTGs | 925 | 7,605 | | | BACT |
| GIBSON COUNTY | TN | DRAFT | 9/4/2012 | NO | NGCC GE 7FA | EFFICIENT CTGs | | | | 1,679,459 | BACT |
| CRICKET VALLEY | NY | FINAL | 9/27/2012 | NO | NGCC GE 7FA | HIGH EFFICIENCY CTGS | 913** | 7,605 | 120 | 3,576,943 | BACT |
| BLACK HILLS | WY | FINAL | 9/27/2012 | NO | NGCC GE LM6000 | EFFICIENT CTGs | 1,100 | | | 187,318 | BACT |
| HESS NEWARK | NJ | FINAL | 10/13/2012 | NO | NGCC GE 7FA | EFFICIENT CTGs | 887 | 7,522 | | | BACT |
| CALPINE DEER PARK | TX | FINAL | 11/29/2012 | NO | NGCC SIEMENS 501FD2 | EFFICIENT CTGs | 920 | 7,730 | | | BACT |
| CALPINE CHANNEL | TX | FINAL | 11/29/2012 | NO | NGCC SIEMENS 501FD2 | EFFICIENT CTGs | 920 | 7,730 | | | BACT |

* Includes solar power component

** Calculated based on heat rate Btu/kWh and emission factor lb/MMBtu

## Appendix C - Table 2

### $CO_2$ Pipeline Construction Cost Estimate

| Description | Cost[1] | Basis |
|---|---|---|
| **Capital Cost:** | | |
| AGI Pipeline - 26" diameter | | 135 mile pipeline[2] |
| Materials | $67,055,624 | $64,632 + $1.85 x L x (330.5 x D^2 + 686.7 x D + 26,960)$ |
| Labor | $114,212,692 | $341,627 + $1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)$ |
| Miscellaneous | $48,372,177 | $150,166 + $1.58 x L x (8,417 x D + 7,234) |
| Right-of-Way | $7,304,017 | $48,037 + $1.20 x L x (577 x D + 29,788) |
| CO2 Surge Tank | $1,150,636 | |
| Pipeline Control System | $110,632 | |
| ***Total Capital Cost*** | ***$238,205,778*** | |
| | | |
| **Annual Operating Cost:** | | |
| O&M Cost | $1,165,320 | $8,632/mile/year |
| ***Total Annual Operating Cost*** | ***$1,165,320*** | |
| | | |
| Capital Recovery Factor | 0.0944 | 7% interest rate and 20 year equipment life |
| | | |
| Annualized Capital Cost | $22,486,625 | |
| | | |
| **Total Annual Cost** | **$23,651,945** | |
| GHG Emissions Removed | 1,314,348 | |
| **Cost Effectiveness ($/ton)** | **$18.00** | |

| | |
|---|---|
| Length in miles (L) = | 135 |
| Diameter in inches (D) = | 26 |

[1] $CO_2$ transport cost is calculated per pipeline cost equations from *Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs, National Energy Technology Laboratory, US Department of Energy, DOE/NETL-2010/1447 (March, 2010).*

## Appendix C, Table 3

### Cost Analysis for Natural Gas Fugitives LDAR Program

| | | |
|---|---|---|
| Monitoring Cost | $2.50 | per component per quarter |
| Number of Valves | 194 | monitored |
| Number of Flanges | 161 | not monitored |
| Number of PRVs | 35 | monitored |
| Number of Pumps | 0 | monitored |
| Number of Compressors | 0 | monitored |
| Total Number Monitored | 229 | monitored |
| Total Monitoring Cost | $2,290 | per year |
| Number of Repairs | 110 | per year (12% of monitored components per quarter) |
| Cost of Repairs | $18,686 | per year @ $200/component (assumed 85% of leaking component need repair; remaining 15% only require minor repair) |
| Cost to Re-monitor Repairs | $275 | per year |
| Total Cost of LDAR | $21,251 | per year (monitoring+repair+re-monitoring) |
| Emission Reduction | 97.08 | ton/year $CO_2$e (based on 28M  reduction of 75%) |
| **Cost Effectiveness** | **$218.90** | **per ton $CO_2$e** |

Example Calculations:

Monitoring cost = ($2.50/component/quarter) x (229 components) x (4 quarters/year) = $2,290/year

Total cost = $2,290/year + $18,686/year + $275/year = $21,251/year

Cost Effectiveness = ($21,251/year) / (97.08 tons/year CO2e) = $218.90/ton CO2e